IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION, STATE OF CONNECTICUT, STATE OF MARYLAND, STATE OF NEW JERSEY, and STATE OF NEW YORK,	:	
	:	Electronically Filed
Plaintiffs,	:	
v.	:	
	:	Civil Action No. 2:05cv0885
ALLEGHENY ENERGY, INC., ALLEGHENY ENERGY SERVICE CORPORATION, ALLEGHENY ENERGY SUPPLY COMPANY, LLC, MONONGAHELA POWER COMPANY, THE POTOMAC EDISON COMPANY, and WEST PENN POWER COMPANY,	:	Chief District Judge Gary L. Lancaster
Defendants.	:	

PLAINTIFFS' POST-TRIAL MEMORANDUM OF LAW (LIABILITY PHASE)

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PRELIMINARY STATEMENT

In the mid-1990s, Allegheny undertook "total rebuilds of the boilers" costing over $50 million each on the two generating units at its Armstrong power plant. At other times in the 1990s, Allegheny undertook large-scale component replacement projects on the generating units at its Hatfield's Ferry and Mitchell power plants, projects which had never before been performed at those units, generally cost millions of dollars, and obliged Allegheny to install special cranes or monorails on site to handle hundreds of thousands of pounds of equipment that Allegheny brought dozens of specialized contract workers on site to remove and install.

Allegheny's goal in these projects was to increase the amount of time that the generating units were available to run. The consequence of that goal was a reasonable expectation that Allegheny would in fact run the units more, burn more coal, and generate more air pollution. The size of the projects, and the reasonable expectation of increased pollution, triggered preconstruction permit and emission control requirements. Because Allegheny did not obtain the permits or comply with the emissions limits, it violated the requirements of five federal and Pennsylvania air pollution control programs:

New Source Performance Standards: Plaintiffs have proved that Allegheny's work on the Armstrong units violated the emissions control requirements of the federal and Pennsylvania new source performance standards ("NSPS") regulations. An existing generating facility becomes subject to NSPS requirements if it undergoes reconstruction. Reconstruction occurs if (1) the cost of the work done exceeds 50 percent of the cost of a "comparable entirely new facility," and (2) it is technologically and economically feasible to meet the emissions reduction requirements. Plaintiffs' experts Dr. Ranajit Sahu and Hugh Larkin offered three analyses that confirmed the projects were "total rebuilds" of the boilers since the cost of the projects exceeded

the 50 percent threshold by millions of dollars. While there is a general presumption of feasibility, Allegheny's own studies from the early 1990s and the early 2000s confirm that it is technologically and economically feasible to meet the NSPS emissions limit for sulfur dioxide ("SO_2") at Armstrong, establishing Allegheny's liability. Liability for reconstruction does not require proof of an expected emissions increase.

New Source/Best Available Technology: Plaintiff Pennsylvania Department of Environmental Protection ("PA DEP") has proven that the work at Armstrong also triggered the new source "best available technology" ("BAT") requirements of Pennsylvania law. An existing facility becomes subject to BAT requirements if it becomes a "new source," and it becomes a "new source" under the same fifty percent test as for the NSPS claims. There is, however, no feasibility requirement for these claims. Accordingly, the evidence described above that shows that the Armstrong work far exceeded the 50 percent threshold establishes liability on these BAT claims as well. Liability for BAT does not require proof of an expected emissions increase.

Prevention of Significant Deterioration: Plaintiffs have proven that the large-scale component replacement projects at the Armstrong, Hatfield's Ferry and Mitchell plants violated the prevention of significant deterioration ("PSD") requirements of federal and Pennsylvania law. The central element of liability on these claims is whether the projects reasonably should have been expected to produce a significant net emissions increase, that is, an expected increase of 40 tons or more. Given that these large units can emit 40 tons of pollution in just a few hours, and given that Allegheny expected these projects to increase the availability of the units by many more hours than necessary to reach that 40-ton threshold, Allegheny was on notice that the reasonable consequence of the projects was that it would use the units more than enough to increase emissions by more than 40 tons. Plaintiffs' expert Robert Koppe confirmed that

Allegheny's expectations of increased availability were reasonable. Plaintiffs' expert Dr. Richard Rosen performed formal emissions projections consistent with the PSD regulations that showed it was reasonable to expect the expected increases in availability to lead to significant net emissions increases of SO_2 and nitrogen oxides ("NO_x").

On the PSD claims for the Hatfield's Ferry and Mitchell projects, Allegheny asserts the regulatory "routine maintenance, repair and replacement" defense, which excludes "*de minimis*" projects from PSD requirements. Because Allegheny's projects were in no way "trifling" efforts, the defense does not apply. Allegheny also asserts that Dr. Rosen's work is unreliable because his projections do not match the actual outcomes. But because the regulations exclude from the PSD emissions calculations the effect of everything except the project, the results of a PSD projection are unlikely to match the actual outcome, so Allegheny's critique lacks foundation.

Nonattainment New Source Review: PA DEP has proven that the work at Armstrong violated the nonattainment new source review ("nonattainment NSR") requirements of Pennsylvania law. The two key elements of this claim are: (1) work at an existing facility that turns the facility into a "new source" under the 50 percent test discussed above, and (2) an anticipated net emissions increase of 40 tons or more per year. PA DEP again proves the first element using the evidence cited in the NSPS section above. On the other element, Pennsylvania law requires use of a potential-to-emit emissions test, and Dr. Rosen's calculations show that Allegheny should have expected emissions to increase under that test by far more than 40 tons.

Title V: Finally, plaintiffs have proven that Allegheny violated the Title V permitting requirements of federal and Pennsylvania law. The Title V program does not impose new emissions limits. Instead, it requires that large power plants obtain omnibus Title V permits that collect and restate, in one document, all of the air pollution control requirements applicable to

the plant that may be set out directly in regulations or in a variety of specialized permits that govern the plants' operation. The Title V regulations require that when the operator of a plant applies for a Title V permit, the operator must disclose all applicable requirements and the information necessary to determine applicable requirements. Because Allegheny did not in its applications disclose the projects at issue in this case or the emissions limits that those projects triggered, PA DEP did not issue permits containing those limits, and Allegheny has been operating its plants in violation of the Title V requirements.

In proving these claims, plaintiffs have relied almost exclusively on Allegheny's own documents and data from the 1990s, either directly or through expert analysis. Allegheny's documents speak for themselves. Plaintiffs' experts have decades of experience in their fields, their analyses are consistent with industry practice and the law in effect at the time of the projects, and their conclusions are consistent with what Allegheny's own documents say.

For its defense, Allegheny is relying principally on the testimony of its past and current employees. That testimony is, in material respects, not credible. Former Allegheny executive Clark Colby testified that Allegheny engineers constantly conferred with Allegheny environmental compliance staff, but none of the engineer witnesses testified about an actual conversation with that staff. For the one pre-project environmental analysis that Allegheny performed for any of the projects in this case, there is no evidence that Allegheny's environmental staff had any role. It is telling that in a defense centered on Allegheny's purported commitment to environmental compliance, Allegheny presented no testimony from its environmental compliance staff, especially current employee Jeannine Hammer, who was "primarily responsible" for Allegheny's permitting obligations at the time of the projects.

In fact, the trial revealed that the non-environmental personnel who apparently made Allegheny's decisions about environmental compliance were ignorant of the relevant law and regulatory standards. Mr. Colby testified that in the 1990s he understood that PSD applicability turned on an hourly emissions test, but a 1990 memorandum from Allegheny's environmental compliance staff unambiguously states that the test was annual. Former Allegheny engineer William Maiden testified that in the 1990s he understood that like-kind projects – projects where a component is replaced with the same or a similar component – were "routine maintenance" exempt from PSD requirements, but by 1990 the U.S. Environmental Protection Agency ("EPA") and a major appellate court decision had announced that such replacements were not automatically exempt.

BACKGROUND AND FACTS

I. THE PARTIES

The five plaintiffs in this action are: the Commonwealth of Pennsylvania, Department of Environmental Protection ("PA DEP") and the States of Connecticut, Maryland, New Jersey and New York. The defendants are Allegheny Energy, Inc. ("Allegheny Energy") and its subsidiaries Allegheny Energy Service Corporation ("Allegheny Service"), Allegheny Energy Supply Company, LLC ("Allegheny Supply"), Monongahela Power Company ("Monongahela"), the Potomac Edison Company ("Potomac") and West Penn Power Company ("West Penn"). The defendants are collectively referred to in this brief as "Allegheny." Before September 1997, Allegheny Energy was named Allegheny Power System, Inc., and before July 1999, Allegheny Service was known as Allegheny Power Service Corporation. PTX 24 at 6; PTX 42 at AE_DUN_00571622.

II. THE FEDERAL CLEAN AIR ACT AND RELATED PENNSYLVANIA LAW

In this section, as general background, plaintiffs set out a brief introduction to the statutory and regulatory provisions relevant to plaintiffs' claims. Plaintiffs provide more specific legal authority and analysis in the Argument section below.

A. National Ambient Air Quality Standards and State Implementation Plans

In 1970, Congress significantly restructured federal air pollution law, creating the modern Clean Air Act out of "dissatisfaction with the progress of existing air pollution programs." *Alaska Dept. of Env'l Cons. v. EPA*, 540 U.S. 461, 469 (2004) (quoting *Union Elec. Co. v. EPA*, 427 U.S. 246, 249 (1976)). In particular, Congress directed EPA to set nationwide air quality standards for a number of air pollutants, including SO_2, NO_x and ozone. *See, e.g.*, 42 U.S.C. § 7409(a); *Save Our Health Org. v. Recomp of Minn., Inc.*, 37 F.3d 1334, 1336 n.2 (8th Cir. 1994). These standards, known as National Ambient Air Quality Standards, or NAAQS, "define [the] levels of air quality that must be achieved to protect public health and welfare." *Alaska*, 540 U.S. at 469 (quoting R. Belden, *Clean Air Act* 6 (2001)). Based on these threshold pollutant levels, EPA classifies each county across the nation as one of the following: (1) an attainment area, if the level of the pollutant in the air is low enough to meet the standard; (2) as a nonattainment area, if the level of the pollutant exceeds the standard; or (3) uncategorizable, if insufficient data is available. 42 U.S.C. § 7407(d)(1)(A) & (B). Nonattainment areas for ozone may be further categorized as "severe," "serious," "moderate," "marginal," or "incomplete data.."

Because each pollutant has its own NAAQS, an area can be in attainment status for one pollutant and nonattainment status for another.

Under the Clean Air Act, a state implementation plan, or SIP, is the set of air pollution regulations or other requirements that a state promulgates to achieve and maintain compliance with the NAAQS. *See* 42 U.S.C. § 7410(a)(1) ("a plan which provides for implementation, maintenance, and enforcement of [NAAQS]"); *Alaska*, 540 U.S. at 469-70. A state's original SIP and later revisions are subject to EPA review and approval. 42 U.S.C. § 7410(a)(1); *Alaska*, 540 U.S. at 470-71. Once approved by EPA, SIP provisions have the force of federal law. *See, e.g.*, *Her Majesty the Queen in Right of the Prov. of Ont. v. Detroit*, 874 F.2d 332, 335 (6th Cir. 1989); *Union Elec. Co. v. EPA*, 515 F.2d 206, 211 (8th Cir. 1975), *aff'd*, 427 U.S. 246 (1976).

B. <u>New Source Performance Standards</u>

Among the specific Clean Air Act regulatory programs Congress created in 1970 was the new source performance standards ("NSPS") program. Pub. L. 91-604, § 4(a), 84 Stat. 1683 (1970). The NSPS program requires that certain new and modified stationary sources of air pollutants meet strict emission standards. 42 U.S.C. § 7411(e).

NSPS requirements apply to certain specific categories of stationary sources. 42 U.S.C. § 7411(b)(1)(A). EPA designates a category of sources if the type of source "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* EPA has designated electric utility steam generating units ("EUSGUs") as an NSPS category. *See* 40 C.F.R. §§ 60.40 & 60.40Da.

For each designated category, EPA sets NSPS emissions standards specific to that category. 42 U.S.C. § 7411(b)(1)(B). NSPS emissions limitations are based on technological feasibility: they are set to "reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the [EPA] Administrator determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1). A facility or source

may be subject to more restrictive emissions standards under other Clean Air Act or state programs, such as PSD or nonattainment NSR. 40 C.F.R. § 60.10; 1 J. Stensvaag & C. Oren, *Clean Air Act – Law and Practice* at 2-12 - 2-12.1 (1995). In 1979, EPA established NSPS emissions limitations for SO_2, NO_x and PM for EUSGUs. 44 Fed. Reg. 33580 (June 11, 1979) [PTX 2160 (d)][1] (promulgating 40 C.F.R. §§ 60.42Da-60.44Da).

The principle that underlies the NSPS is that the best time to require that pollution controls be installed is when emissions sources are first constructed or undergoing significant equipment replacement or other physical or operational changes. 40 Fed. Reg. 58415, 58417 (Dec. 16, 1975) [PTX 2201 (d)]. One of the goals of NSPS is to reduce emissions of air contaminants by imposing more rigorous emissions standards on new emission units as old emission units are retired. S. Novick (Ed.), *Law of Environmental Protection* at 12-124 (2002).

An EUSGU is subject to NSPS if it is a "new source," which is defined to include any stationary source the "construction *or modification* of which is commenced" after EPA establishes the NSPS emissions standards for that category. 42 U.S.C. § 7411(a)(2) (emphasis added). In particular, an existing EUSGU that undergoes "reconstruction" is subject to NSPS, irrespective of any change in its emissions rate. 40 C.F.R. § 60.15(a) [PTX 2219 (d)]. EPA regulations define "reconstruction" to mean:

> the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

[1] For the Court's convenience, plaintiffs have provided as demonstratives copies of certain regulations, administrative decisions, agency applicability determinations and other legal guidance documents. All demonstratives, whether legal or factual, are identified with a "(d)" after the exhibit number.

> (2) It is technologically and economically feasible to meet the applicable [NSPS] standards . . . .

40 C.F.R. § 60.15(b) [PTX 2219 (d)]. EPA explained that the purpose of the reconstruction provision was to prevent "circumvention of the law" by owners and operators who, rather than build a new facility, would replace components to such a degree that the facility is essentially a new facility. 40 Fed. Reg. at 58417 [PTX 2201 (d)], *see also* PTX 134 at 5-1 (EPA study stating that "reconstruction is a change which is so substantial as to classify the source as a new source rather than altered existing source").

It is unlawful for a source subject to NSPS emissions standards to emit pollution in excess of those standards. 42 U.S.C. § 7411(e). The NSPS requirements apply to a facility irrespective of whether it is located in an attainment area or a nonattainment area.

Effective as of August 1979, Pennsylvania added provisions to its environmental regulations to adopt and incorporate by reference the federal NSPS provisions. 9 Pa. Bull. 1447 (Apr. 27, 1979) (promulgating 25 Pa. Code §§ 122.1-122.3). In 1985, EPA delegated to PA DEP the authority to implement and enforce those standards. 50 Fed. Reg. 34140 (Aug. 23, 1985). Under Pennsylvania law any violation of Pennsylvania air quality regulations is unlawful. 35. P.S. § 4008. Accordingly, NSPS definitions and requirements under Pennsylvania law are identical to the federal NSPS regulatory requirements, and any violation of the federal NSPS regulations by a Pennsylvania facility is also a violation of Pennsylvania law.

C. New Source Review: Prevention of Significant Deterioration and Nonattainment New Source Review

In 1977, Congress concluded that the 1970 Clean Air Act amendments had not adequately addressed the nation's air pollution problems and further amended the Act. *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007). In particular,

Congress enacted two programs collectively known as new source review: the prevention of significant deterioration ("PSD") program, and the nonattainment new source review ("nonattainment NSR") program. Pub. L. 95-95, §§ 127, 129, 1977 U.S.C.C.A.N. (91 Stat.) 731, 745.

Congress created the PSD program to address air pollution issues in attainment areas. Air quality in attainment areas already met federal standards, but as the name indicates, the purpose of the "prevention of significant deterioration" program is to prevent air quality in those areas from worsening. *Alaska*, 540 U.S. at 470 (purpose of PSD is "to ensure that the air quality in attainment areas or areas that are already 'clean' will not degrade") (quoting R. Belden, *Clean Air Act* 43 (2001)). To achieve this end, Congress created a preconstruction permitting program that subjected covered facilities in those areas to stringent air pollution control requirements, known as "best available control technology," or BACT. 42 U.S.C. § 7475(a)(1) & (4).

The statute provided that these permitting and pollution control requirements were triggered if a utility undertook "construction," which Congress defined to include "modification." 42 U.S.C. § 7479(2)(C). Congress then defined "modification" very broadly: "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. §§ 7411(a)(4). Thus, Congress created no exemptions: *any* physical change which would produce *any* increase in emissions was subject to the PSD preconstruction permitting requirements.

To implement the PSD statute, EPA promulgated regulations in 1980 and subsequently revised those regulations in 1992. The regulations subject certain existing power plants to PSD requirements if they undergo a "major modification." Consistent with the statute, "major

modification" had a two-pronged definition: (1) "any physical change in or change in the method of operation" of a covered plant that (2) "would result in a significant net emissions increase" of certain pollutants. 40 C.F.R. § 52.21(b)(2)(i)[2] [PTX 2210 (d)]. The regulations then set numerical thresholds for what constituted a "significant" net emissions increase. 40 C.F.R. § 52.21(b)(23) [PTX 2210 (d)]. Under the regulations, a plant at which a major modification is performed becomes subject to BACT emissions limits. 40 C.F.R. § 52.21(i)(2), (j)(3) [PTX 2210 (d)].

Congress enacted the nonattainment NSR program to improve air quality in nonattainment areas so as to bring those areas into compliance with the NAAQS. EPA promulgated regulations implementing the nonattainment NSR statute in 1980 and 1992 at the same time that it promulgated the PSD regulations. *See*, *e.g.*, 57 Fed. Reg. 32314, 32314-32315 (July 21, 1992) [PTX 2217 (d)] (noting that EPA is amending both its PSD and its nonattainment NSR regulations). Like the PSD regulations, the nonattainment NSR regulations subject certain existing power plants to nonattainment NSR requirements if those plants undergo a "major modification." Under the nonattainment NSR regulations, "major modification" is defined using the same two-pronged test – physical or operational change, and significant net emissions increase – as under the PSD regulations. *See*, *e.g.*, 40 C.F.R. § 52.165(a)(1)(v)(A) [PTX 2210 (d)]; 57 Fed. Reg. at 32316 [PTX 2217 (d)] (nonattainment NSR regulations "contain applicability provisions regarding modification that are largely identical to those in the PSD provisions").

[2] Plaintiffs note that in the early 2000s, EPA amended parts of the PSD regulations. Accordingly, for the Court's convenience, plaintiffs have provided a copy of the PSD regulations in effect at the time of the projects at issue in this case as demonstrative PTX 2210.

Like the PSD regulations, the nonattainment NSR regulations provide that a plant at which a major modification was performed became subject to operational requirements. However, because the nonattainment NSR regulations govern sources in areas where air pollution exceeds the lawful NAAQS limit, the operational requirements are more stringent than for PSD. Thus, the requirements include emissions limitations that achieve the "lowest achievable emissions rate" ("LAER"). 40 C.F.R. § 51.165(a)(1) (requiring that state programs use definitions at least as stringent as those set out in this regulation); 40 C.F.R. § 51.165(a)(1)(xiii) (definition of LAER). LAER is the most stringent emissions limitation under the Clean Air Act. *See*, *e.g.* 42 U.S.C. § 7501(3).

A SIP must include PSD and nonattainment NSR permitting programs. 42 U.S.C. § 7410(a)(2)(C) (SIP must include "permit program as required in parts C and D of this subchapter," which are the PSD and nonattainment NSR provisions); *Alaska*, 540 U.S. at 470 (SIP must include PSD program). The PSD and nonattainment NSR requirements set out in a SIP may be more stringent than EPA's PSD and nonattainment NSR requirements. *See* 42 U.S.C. § 7416; 40 C.F.R. § 51.166(a)(7)(iv) & (b) (PSD); 40 C.F.R. § 51.165(a)(1) (nonattainment NSR); *Her Majesty the Queen in Right of the Prov. of Ont. v. Detroit*, 874 F.2d 332, 336 (6th Cir. 1989).

In June 1983, Pennsylvania incorporated the federal PSD regulations by reference into its SIP. 13 Pa. Bull. 1940 (June 18, 1983) (promulgating 25 Pa. Code § 127.83). In 1984, EPA approved this adoption and incorporation by reference. 49 Fed. Reg. 33127 (Aug. 21, 1984). Accordingly, since 1983, PSD requirements under Pennsylvania law are identical to the federal PSD requirements, and any violation of the federal PSD regulations by a Pennsylvania power plant is also a violation of Pennsylvania law.

Plaintiffs discuss Pennsylvania's nonattainment NSR regulations in Background and Facts section II.H.1 below.

D. <u>Title IV: the Acid Rain Cap-and-Trade Program</u>

In 1990, Congress amended the Clean Air Act, adding Title IV to require reductions in SO_2 emissions from certain utilities to address the problem of acid rain. *See* Pub. L. No. 101-549, § 401, 1990 U.S.C.C.A.N. (104 Stat.) 2399, 2584-2631 (codified at 42 U.S.C. §§ 7651-7651*o*). Specifically, Phase I of the Title IV program created a "cap-and-trade" system under which the nation's 110 highest-emitting utility plants were collectively required to meet a national SO_2 emissions limitation by January 1, 1995. *See* 42 U.S.C. § 7651c; 58 Fed. Reg. 3590, 3590 (Jan. 11, 1993).

To each plant covered by the Phase I requirements, EPA allocated a certain number of those allowances based on the plant's historic fuel use and preexisting regulatory obligations. 42 U.S.C. § 7651c(e)(2); 58 Fed. Reg. at 3590, 3687. A covered plant was then in compliance with the Phase I requirements for a given year so long as its SO_2 emissions for that year did not exceed the number of emissions allowance that it held for that year. *See, e.g.*, 58 Fed. Reg. at 3590. One way, therefore, that a plant could comply would be to reduce its SO_2 emissions to the amount of its allocated allowances, and it could make that reduction in a several ways, such as: operating the plant for fewer hours, burning fuel with a lower sulfur content, or installing a flue gas desulfurization unit, known more colloquially as a "scrubber," to remove SO_2 from the plant's exhaust gases. *Id.*

The Title IV allowances were fully transferable, however. *Id.* So a plant could choose to emit *more* SO_2 than its initial allocation of allowances and still comply with Phase I requirements so long as the plant obtained a sufficient number of additional allowances on the

open market: this was the "trade" part of the cap-and-trade system. *Id.* Alternatively, a plant could choose to emit *less* than the amount of its initial allocation of allowances, and in that case could sell or otherwise transfer its excess allowances. *Id.* A utility could transfer allowances from a plant with excess allowances to another plant that was short on allowances to obtain compliance at both plants. Thus, Title IV imposed no fixed emissions limit on a plant, since the plant could raise or lower the amount of its lawful emissions by buying or selling allowances.

There was also a Phase II of the Title IV program, which covered a much greater number of plants and accordingly had a higher overall cap on emissions. *See* 42 U.S.C. §7651d; 40 C.F.R. § 73.10(b). EPA regulations required that each utility operating a Phase I or Phase II plant obtain a Title IV permit for each such plant. 40 C.F.R. § 72.30(a). Consistent with the "cap-and-trade" nature of Title IV, however, neither the Phase I nor the Phase II permits set fixed SO_2 emissions limits. *See, e.g.*, PTX 1938, PTX 1940, PTX 1942, PTX 1944, PTX 1946 (Title IV permits for Armstrong, Hatfield's Ferry and Mitchell).

Title IV left the PSD and other requirements of CAA Title I unaffected. *See, e.g.*, 57 Fed. Reg. at 32315 [PTX 2217 (d)] ("[i]n passing title IV, Congress did not suspend any requirements of title I").

The Armstrong and Hatfield's Ferry plants were among the 110 plants that Congress designated for Phase I of Title IV. 42 U.S.C. § 7651c(e) (Table A). Through a separate Title IV regulatory provision regarding "substitution units," Allegheny voluntarily chose to subject the Mitchell plant to Phase I requirements as well. *See* 40 C.F.R. § 72.41; PTX 21 at 19 (noting that Allegheny chose to subject all Phase II units to Phase I requirements).

E. Reasonably Available Control Technology for NO_x Emissions, or RACT

Another provision that Congress enacted in the 1990 Clean Air Act amendments required that certain major stationary sources of NO_x install "reasonably available control technology" ("RACT") to reduce NO_x emissions. 42 U.S.C. § 7511a(b)(2) (establishing RACT requirements for emissions of volatile organic compounds ("VOCs")); 42 U.S.C. § 7511a(f) (extending RACT requirements for VOC emissions to NO_x emissions). Congress was concerned about NO_x emissions because they react in the atmosphere with VOCs and other compounds to form ground-level ozone. *See, e.g.*, 57 Fed. Reg. 35542, 35544 (Aug. 10, 1992). The purpose of the 1990 RACT provision was to address ground-level ozone problem. *See, e.g.*, 57 Fed. Reg. 13498, 13501 (Apr. 16, 1992) (noting that one of Congress' "chief motivations" in enacting the 1990 amendments was "the failure of areas to attain the ozone . . . standards"); T.T.[3], Sept. 14, 2010, at 100;23-101:4. The RACT requirement covered plants in the multistate northeastern ozone transport region, including the Armstrong, Hatfield's Ferry and Mitchell plants. 42 U.S.C. § 7511a(f) (extending RACT requirements to NO_x emissions), 42 U.S.C. §§ 7511c(a) & (b)(1)(B) (extending RACT requirements to sources in the ozone transport region); *see also* 60 Fed. Reg. at 2914 ("RACT is applicable statewide in Pennsylvania").

[3] References to "T.T." are to the trial transcripts.

The "reasonable" control technology that constitutes RACT is less stringent than the "best" control technology that constitutes BACT under the PSD requirements.[4] Thus, reductions of emissions sufficient to satisfy RACT would not satisfy the PSD BACT requirements.

F. The Title V Operating Permit Program

In the 1990 Amendments to the Clean Air Act, Congress also added Title V, which for the first time established a federal operating permit program for air pollution sources. Pub. L. 101-549, § 501, 1990 U.S.C.C.A.N. (104 Stat.) 2399, 2635-2648 (codified at 42 U.S.C. §§ 7661-7661*f*). A Title V permit consolidates all applicable operating requirements for a covered emissions source – whether from statutes, regulations or other permits -- into one document and does not independently create any additional legal requirements. 42 U.S.C. § 7661c(a); 40 C.F.R. §§ 70.2, 71.2 (definitions of "applicable requirements"); 66 Fed. Reg. 63180, 63180 (Dec. 5, 2001) ("[o]perating permit programs are intended to consolidate into single federally enforceable documents all requirements of the [CAA] that apply to individual sources [of air pollution]"); *United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 651-52 (M.D.N.C. 2003), *aff'd*, 411 F.3d 539 (4th Cir. 2005), *vacated on other grounds and remanded sub nom. Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561 (2007). In 1996, EPA approved Pennsylvania's Title V program as part of Pennsylvania's SIP, thus authorizing PA DEP to operate a federally recognized Title V program. 61 Fed. Reg. 39597 (July 30, 1996).

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[4] *See, e.g.*, 48 Fed. Reg. 51942, 51943 (Nov. 15, 1983) (referencing "the more stringent application of BACT rather than RACT"); 59 Fed. Reg. 41998, 42010 (Aug. 16, 1994) (in interpreting the CAA, noting that "[a] plain-English interpretation of the term 'best' implies a generally higher standard of performance than one that may be considered 'reasonable'"); 61 Fed. Reg. 38250, 38256 (July 23, 1996) ("RACT emission limits can be less stringent than . . . BACT"); 68 Fed. Reg. 63991, 63992 (Nov. 12, 2003) ("EPA requires some new sources to be subject to more stringent requirements than the RACT requirements . . . , such as [BACT]").

Under the statutes and regulations, it is unlawful for major stationary sources to operate without obtaining Title V operating permits. 42 U.S.C. § 7661a(a) (unlawful for "major sources" to operate without permit"); 42 U.S.C. § 7661(2) (definition of major source includes major stationary source); *see also* 25 Pa. Code § 127.402(a)[5] [PTX 2209 (d)] (requiring operating permits for stationary air contamination source); 25 Pa. Code § 127.501 (noting additional requirements for "Title V facilities"); 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "Title V facility").

Title V operating permits must include "emission limitations and standards" and any other operating conditions necessary to assure compliance with "applicable requirements" of the Clean Air Act and the Pennsylvania SIP. 42 U.S.C. § 7661c(a); 40 C.F.R. §§ 70.6(a)(1) & 71.6(a)(1); 25 Pa. Code § 127.512(h) [PTX 2209 (d)]; *see also* 25 Pa. Code § 127.502(a) [PTX 2209 (d)] ("for Title V facilities, the applicable requirements for stationary air contamination sources in the Title V facility shall be included in the operating permit."). "Applicable requirements" include: (1) "[a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA . . . that implements the relevant requirements of the Act"; (2) any applicable NSPS standard or requirement; and (3) "[a]ny term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act." 40 C.F.R. §§ 70.2 & 71.2; *see also* 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "applicable requirements"). In addition to the emissions limitations and standards, in the event that a facility

[5] The Pennsylvania air regulations may have changed since the time of the projects at issue in this case. Accordingly, for the Court's convenience, plaintiffs have provided a copy of the regulations as in effect at the relevant times as demonstratives PTX 2208 and PTX 2209.

is not in compliance with federal or state law, Title V permits must contain a compliance schedule. 40 C.F.R. §§ 70.6(c)(3) & 71.6(c)(3); 25 Pa. Code § 127.513(3) [PTX 2209 (d)].

G. Citizen Suits

In the 1970 Clean Air Act Amendments, Congress authorized "any person," including states, to bring a civil "citizen suit" action to enforce the Clean Air Act. 42 U.S.C. § 7604(a). In particular, subsection (a)(1) authorizes citizen suits against any person who is alleged to have violated or to be in violation of an emission standard or limitation under the Clean Air Act. 42 U.S.C. § 7604(a)(1). In addition, subsection (a)(3) authorizes citizen suits against any person who constructs any new or modified major emitting facility without a required PSD or nonattainment NSR permit. 42 U.S.C. § 7604(a)(3). The citizen suit provision gives district courts jurisdiction (1) to award injunctive relief to compel compliance with the Clean Air Act and for other purposes, and (2) to assess civil penalties, which are payable to the U.S. Treasury.[6] 42 U.S.C. § 7604(a), (g).

The citizen suit statute has a notice provision: no citizen suit under subsection (a)(1) may be commenced without providing 60-days' notice of the claims to the alleged violator, the EPA administrator, and the state in which the violation occurred. 42 U.S.C. § 7604(b)(1)(A). The statute does not impose any notice requirement with regard to citizen suits brought under subsection (a)(3). *See* 42 U.S.C. § 7604(b) *passim*.

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[6] Up to $100,000 of such penalties can be used to finance projects to enhance public health or the environment. 42 U.S.C. § 7604 (g).

H. Pennsylvania State Law Programs: Nonattainment NSR and BAT

1. Nonattainment NSR

PA DEP promulgated replacement nonattainment NSR regulations in January 1994. 24 Pa. Bull. 443 (Jan. 15, 1994) (promulgating 25 Pa. Code §§ 127.201-127.216). EPA granted limited approval of those regulations in 1997. 62 Fed. Reg. 64722, 64722-64725 (Dec. 9, 1997). As a result, before 1997, the nonattainment regulations were enforceable only as state law.

These nonattainment NSR requirements apply to larger existing facilities in a nonattainment area for sulfur oxides ("SO_x") or ozone that undertakes a "major modification." As under the federal regulations, under the Pennsylvania regulations a "major modification" is a physical change or change in the method of operation of a major facility that results in an increase in emissions equal to or exceeding certain emission rate thresholds. 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "major modification"). A major modification includes the installation of a "new source." 25 Pa. Code §§ 127.203(a)(2) & (b)(1) [PTX 2209 (d)]. The regulations define "new source" to include, among other things, a stationary air contamination source that was modified so that the fixed capital cost of new components exceeded 50 percent of the fixed capital costs that would be required to construct a comparable entirely new source. 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "new source").

Under the regulations, PA DEP will not issue a nonattainment NSR permit, or "plan approval," as they are called in Pennsylvania, for a major modification, or allow continued operation of an existing plant, unless several conditions are met, including installation of pollution control equipment or other steps to reduce emissions to the LAER level. 25 Pa. Code § 127.205 [PTX 2209 (d)]; *see also* 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "LAER").

2. Best Achievable Technology

In addition, under Pennsylvania law an owner or operator of any new air contamination source must obtain written approval from the Commonwealth before commencing construction or modification of the new source. 35 P.S. § 4006.1(a); 25 Pa. Code § 127.11 [PTX 2209 (d)]. This pre-construction permit is called a "plan approval." 25 Pa. Code § 127.11 [PTX 2209 (d)]. For the purpose of this provision, a source becomes a "new source" under the same 50 percent test as used under the Pennsylvania nonattainment NSR regulations above.

Pennsylvania regulations specify the requirements for issuance of a plan approval. 25 Pa. Code § 127.12(a) [PTX 2209 (d)]. Two of these requirements are particularly germane to this proceeding. First, the application must show and PA DEP must find that the source will comply with all applicable requirements of federal and Pennsylvania air quality regulations. 25 Pa. Code § 127.12(a)(4) [PTX 2209 (d)]. This includes a requirement to satisfy Pennsylvania's nonattainment NSR regulations. 25 Pa. Code §§ 127.201-127.216 [PTX 2209 (d)].

Second, the application must demonstrate, and PA DEP must find, that emissions will be the "minimum attainable through use of best available technology." 25 Pa. Code § 127.12(a)(5) [PTX 2209 (d)]; *see also* 25 Pa. Code. § 127.1 [PTX 2209 (d)] ("[n]ew sources shall control the emission of air pollutants to the maximum extent, consistent with the best available technology as determined by [PA DEP]."). Pennsylvania regulations define best available technology ("BAT") as:

> Equipment, devices, methods or techniques as determined by [PA DEP] which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available.

25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "best available technology"). BAT standards apply to all air pollutants regulated under Pennsylvania law, including without limitation SO_2,

NO_x, ozone, PM, and mercury and other hazardous air pollutants. 35 P.S. § 4003; 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of BAT governs emissions of "air contaminants"); *see also* 25 Pa. Code § 121.1 [PTX 2208 (d)]. BAT-based emission standards may be more stringent than NSPS, and may cover pollutants that NSPS does not regulate. T.T., Sept. 13, 2010, at 64:7-65:1.

III. COAL-FIRED POWER PLANTS

A. How Coal-Fired Power Plants Operate

Conceptually, the process by which coal-fired power plants generate electricity is straightforward: burning coal generates heat, the heat converts water into steam, and the steam turns a turbine which generates electricity. T.T., Sept. 13, 2010, at 44:1-5. More specifically, pulverized coal is burned in a furnace which is enclosed by walls composed of tubes with water flowing through them ("waterwall tubes"). T.T., Sept. 13, 2010, at 46:15-25, 47:13-18, 48:5-10, 49:1-7. The fire heats the water in the waterwall tubes, and the water becomes steam and flows through other groups of tubes in the boiler, such as superheaters and reheaters, which increases the steam's temperature and pressure. T.T. Sept. 13, 2010, 48:14-21, 49:3-25. The superheated and pressurized steam leaves the boiler and spins a turbine that turns a generator that generates electricity. T.T. Sept. 13, 2010, at 56:4-8. After the steam has given up its energy to the turbines, it is condensed back into water and is sent through the economizer, which begins to heat the water again, and then back into the waterwall tubes again. T.T., Sept. 13, 2010, at 56:2-15.

The boiler generates air pollutants, such as SO_2, NO_x and particulate matter, through chemical reactions that occur as the coal burns. T.T., Sept. 13, 2010, at 51:11-25. Those pollutants are sent upward into the atmosphere through a stack, after passing through pollution control devices, if any. T.T. Sept. 13, 2010, at 53:9-54:1. When people breathe air contaminated

with SO_2 and NO_x, they can suffer serious health effects, such as airway inflammation and decreases in lung function. The consequences of these health effects range from the onset of respiratory problems to hospital admissions. 75 Fed. Reg. 6474, 6480-81. (Feb. 9, 2010). Even short-term exposure to NO_2 and SO_2 can have a direct effect on respiratory health, and people with asthma and chronic obstructive pulmonary disease are at even greater risk of adverse health effects. *Id*. at 6474. Because of the number of people at risk, exposure to NO_2 and SO_2 has a significant impact on public health in the United States. *Id.*

Ozone is another pollutant, formed in the air by the interaction of NO_x from power plants and other sources with hydrocarbons and sunlight. 1990 U.S.C.C.A.N. (104 Stat.) 3392. Ozone is fatal at high concentrations, and healthy adults and children begin to experience chest pain, shortness of breath and other health problems at lower concentrations. *Id.* The elderly, children and people with pre-existing respiratory problems are the most likely to be injured from exposure to ozone. *Id.* at 3393. The most troubling aspect of ozone pollution is the scientific evidence that long-term chronic exposure may produce accelerated aging of the lung analogous to the effect of cigarette smoking. *Id.* at 3392. Regulatory efforts to reduce ozone pollution focus on reducing emissions of NO_x and other ozone precursors.

There are a variety of available pollution control measures: SO_2 emissions can be substantially reduced by flue gas desulfurization (“FGD”) units known as “scrubbers,” and NO_x emissions can be substantially reduced by selective catalytic converters (“SCRs”). T.T., Sept. 13, 2010 at, 53:9-54:10, 54:11-25, 55:12-56. In the 1990s, none of the generating units at issue in this case had scrubbers except for Mitchell 3. None of those units had SCRs.

Electric generating units are sometimes forced to shut down because of a problem with a piece of equipment that must be repaired before the unit can operate again. These shutdowns are

known as forced outages; they are most commonly caused by leaks in boiler tubes, which are exposed to extremes of temperature and pressure. T.T., Sept. 14, 2010, at 203:10-25. Because a unit is not available to generate electricity when it is shut down in a forced outage, a utility will have to operate its more expensive units to replace the lost power or purchase more expensive replacement power from an outside utility. The greatest cost of a forced outage is this cost of replacement power. PTX 704 at AE_DUN_00005227-28; D.T.[7] (David Piktel), Sept. 29, 2009, at 93:3-94:8; T.T., Sept. 20, 2010, at 19:16-20:8.

B. The Electric Utility Industry's Successful Efforts to Improve the Availability of Its Power Plants

A large number of coal-fired power plants constructed in the late 1960s and early 1970s began to experience substantially more problems than earlier units constructed in the 1950s. As a result, these newer units were available to operate only 60 to 65 percent of the time. T.T., Sept.14, 2010, at 206:16-207:8. For example, in 1976 the average coal fired electric generating unit was available only 250 days in the year. T.T., Sept. 20, 2010, at 75:4-14.

There was an industry-wide response to the crisis of declining availability: the creation of boiler availability improvement programs. T.T., Sept. 20, 2010, at, 208:11-209:4. The essential element in these programs was replacement of major deteriorated pieces of equipment with new and better designed ones. T.T., Sept. 14, 2010, at 208:11-209:4; T.T., Sept. 20, 2010, at 75:22-76:5. These boiler availability improvement programs were extremely successful – by 1990 the average coal fired generating unit was available to operate 300 days a year, an increase of 50 days per year from the mid-1970s. T.T., Sept. 20, 2010, at 75:15-17. Improvements in unit availability continued throughout the 1990s and availability increased nine days per year on average. T.T., Sept. 20, 2010, at 76:6-13.

[7] References to "D.T." are to designated excerpts of deposition transcripts.

Beginning in the 1980s, the electric utility industry also embarked on programs to extend the lives of generating units that were constructed in the 1950s and were then reaching the end of their design life. T.T., Sept. 14, 2010, at 210:10-211:1. These programs, known as "life extension," also required the replacement of major deteriorated components with new and better designed ones that enabled units designed for 30 to 35 years of use to last for 50 or even 60 years. T.T., Sept. 14, 2010, at 210:10-211:7; DTX 97 at 0001, 0005.

C. Allegheny Replaced the Major Deteriorated Components at Issue in This Case to Improve the Availability of Its Generating Units

Allegheny, like other electric utilities, knew that it could improve the availability of its generating units by replacing major deteriorated components that were causing numerous forced outages. And, like other utilities, Allegheny implemented boiler availability improvement programs to reduce those outages and increase availability; those programs in the 1990s included every major component replacement at issue in this case. PTX 563.

When Allegheny decided whether to replace a major deteriorated component, the determinative factor was whether the benefits from the projected availability increase would outweigh the cost of purchasing and installing the new component. T.T., Sept. 27, 2010, at 149:10-152:5. In every Allegheny economic analysis justifying a component replacement, the major financial benefit was the fact that there would be no cost for replacement power because the unit would become more available and therefore generate more electricity – the electricity that Allegheny previously had to purchase elsewhere during the forced outages the old component had been causing. PTX 704; T.T. Sept. 20, 2010 at 19:16-21:23.

Allegheny's Chief Executive Officer Paul Evanson knew that major component replacements increase unit availability and that increased availability results in increased electric generation. PTX 1842 at 2. In 2005, when Allegheny embarked on another availability

improvement program, Mr. Evanson told energy analysts and shareholders that Allegheny hoped to increase availability at its supercritical plants by 6 percent. PTX 1827 at 2. The next year, he reported that the forced outage rate had already been reduced from 12 to 5 percent at four units at which Allegheny had already performed component replacement projects. PTX 1842 at 3. Mr. Evanson quantified the financial benefits of this increased availability when he stated "that every percentage point improvement in power plant availability is worth between 10 and 12 million dollars in additional revenue." PTX 1840 at 2. Such increases in generation and revenue are precisely why Allegheny undertook the PSD Projects at issue in this case. T.T., Sept. 20, 2010, at 21:4-23.

IV. <u>THE POWER PLANTS AND PROJECTS AT ISSUE IN THIS CASE</u>

A. <u>The Power Plants</u>

This litigation concerns three coal-fired electricity generating stations in western Pennsylvania operated by Allegheny: Armstrong, Hatfield's Ferry ("Hatfield") and Mitchell. Docket Item 430 ¶ 4. The Armstrong power station has two subcritical boilers, each with a capacity of 170 to 180 megawatts. Unit 1 began operating in 1958 and unit 2 in 1959. Docket Item 431 ¶¶ 9, 10. The Hatfield's Ferry power station has three supercritical boilers, each with a capacity of 555 megawatts. Docket Item 430 ¶ 17; T.T., Sept. 20, 2010, at 11:3-13. Unit 1 began operating in 1969, unit 2 in 1970 and unit 3 in 1971. Docket Item 430 ¶¶ 18, 19, 20. The Mitchell power station has three generating units, but only one, unit 3, is coal-fired. It is a 288 megawatt subcritical boiler that began operating in 1963. Docket Item 430 ¶¶ 62, 63; PTX 958 at AE_HQ_00376670.

B. <u>The Magnitude of the Projects</u>

From 1993 through 1999, Allegheny completely rebuilt the two boilers at the Armstrong power station. It also replaced major deteriorated components with new and upgraded versions at all three units at the Hatfield's Ferry power station and at one unit at the Mitchell power station. Allegheny did all these projects to increase unit availability and generation.

1. The Armstrong Reconstruction Projects

Allegheny shut down Armstrong units 1 and 2 for unprecedented work during eight month planned outages in 1995 and 1994, respectively. T.T., Sept. 13, 2010, at 77:10-14; PTX 356 at R-3 22824. In those outages, Allegheny removed the furnaces, including all the waterwalls, installed a redesigned furnace, and replaced every major component in the back end of the boiler – the superheaters, reheaters, economizers, and air heaters – with a new and upgraded version. PTX 356 at R-3 22824 –R-3 22831; T.T., Sept. 13, 2010, at 84:4-11. After the Armstrong boilers were rebuilt, the only equipment left from the original boilers were the coal pulverizers, the steam drums and some downcomer tubes. T.T., Sept. 13, 2010, at 84:12-18; PTX 356 at R-3 22824 - 831. These rebuilding projects cost $52,431,805 for unit 1 and $53,302,358 for unit 2. PTX 908. The cost of each Armstrong boiler rebuild was more than 50 percent of the cost of constructing an entirely new comparable boiler. PTX 906, PTX 908, PTX 129. Plaintiffs refer to the entirety of the work done on the Armstrong boilers as the "Reconstruction Projects."

2. The PSD Projects

As a part of the unprecedented Reconstruction Projects at Armstrong, and separately at the Hatfield's Ferry and Mitchell 3 units, Allegheny did a number of large scale component replacement projects that are the subject of plaintiffs PSD claims (the "PSD Projects").

a. The Armstrong PSD Projects

Allegheny divided the work on the Armstrong boilers that it performed in 1994 and 1995 into two separate projects authorized by two separate work orders. PTX 254, PTX 363. At each unit, Allegheny designated one portion of the work as the "low-NO_x burner project," which included the replacement of the existing burners and certain burner-related equipment, along with the replacement and upgrading of the primary furnace, radiant superheater, boiler casing, and boiler insulation system. PTX 363 at R-3 10001, R-3 10019

At each unit, Allegheny designated the remaining work as the "Boiler Project," which included the replacement of the superheater, reheater, economizer, air heaters, ductwork, and sootblowers. PTX 254 at R-3 09501, R-3 09506. Plaintiffs refer to this remaining work as the Armstrong "PSD Projects"; thus, the Armstrong PSD Projects were a subset of the Armstrong Reconstruction Projects. The PSD Project work at units 1 and 2 cost $28,657,739 and $29,912,514, respectively, and were accounted for as capital expenses. PTX 898.

b. The Hatfield's Ferry Lower Slope PSD Projects

In 1995, Allegheny began planning to replace the lower slopes, inlet headers, ash hoppers and seal skirts ("the lower slope projects") at all three Hatfield units. PTX 704. Tube failures in the lower slopes had caused 2,750 hours of forced outage in the previous three years, reducing unit availability by an average of 3.5 percent and as high as 7 percent. PTX 704 at AE_DUN_00005218 - 219. Allegheny replaced the lower slopes at the Hatfield units in order to increase the availability of the Hatfield plant – a project that Allegheny described as "very aggressive." PTX 704 at AE_DUN_00005220; PTX 707. The complete replacement of the lower slope tube panels was necessary because repeated attempts at partial replacements had failed. Docket Item 430 ¶ 30.

Allegheny predicted that the three Hatfield units would experience eight four-day forced outages – 768 hours of outage time – each year because of tube leaks in the lower slopes if the projects were not undertaken. PTX 704 at AE_DUN_00005227 - 228. Allegheny assumed there would be no forced outages caused by lower slope tube leaks for the next twenty-five years if the projects were undertaken. *Id.* at AE_DUN_00005229. As a result, Allegheny predicted it would save $28,516,863 by not having to purchase replacement energy because of the lower slope projects. *Id.* at AE_DUN_00005228. Allegheny also assumed that the three Hatfield units would generate more electricity after the lower slope projects because the units would not be shut down each year for outages due to problems with the lower slope tubes as they had been before the projects. T.T., Sept. 20, 2010, at 50:21-25; PTX 704 at AE_DUN_00005227 - 229.

The lower slope projects were large-scale undertakings. Docket Item 430 ¶ 58. All the old tubes in the lower slopes were disconnected from the vertical section of the waterwalls, new tube panels were brought into place and temporarily supported until they could be connected, and then more than 2,000 welds were made to connect the ends of the new tubes to the vertical section of the waterwalls. People worked on the projects six days a week in two ten-hour shifts. T.T., Sept. 20, 2010, at 46:18-47:15, 48:11-49:2. All the projects were done by outside contractors and accounted for as a capital expense. Docket Item 430 ¶¶ 29, 32, 51, 55, 59, 60.

Unit 1: Allegheny replaced the Hatfield 1 lower slopes during a ten-week planned outage in the fall of 1997 that lasted slightly more than two months. Docket Item 430 ¶ 27. Allegheny had never before replaced the lower slopes since the unit began operating 28 years earlier. T.T., Sept. 20, 2010, at 49:3-12; Docket Item 430 ¶ 18. The project cost $5,918,077. Docket Item 430 ¶ 31

Unit 2: Allegheny replaced the Hatfield 2 lower slopes during a planned outage in the fall of 1999 that lasted 12 weeks. Docket Item 430 ¶ 49. Allegheny had never before replaced the lower slopes since the unit began operating 27 years earlier. T.T., Sept. 20, 2010, at 49:3-12; Docket Item ¶ 19. The project cost $6,342,917. Docket Item 430 ¶ 54.

Unit 3: Allegheny began planning the Hatfield 3 lower slope project over one year before performing it. Docket Item 430 ¶ 56. The slopes were replaced during a ten-week planned outage in the fall of 1996 and involved four separate outside contractors. Docket Item 430 ¶ 57; T.T., Sept. 20, 2010, at 47:20-48:10. Allegheny had never before replaced the lower slopes since the unit began operating 25 years earlier. *Id.* at 49:3-12; Docket Item 430 ¶ 20. The project cost $6,387,013. Docket Item 431 ¶ 5.

c. The Hatfield 1 Secondary Superheater Outlet Header PSD Project

Allegheny replaced both secondary superheater outlet headers ("SSOHs") at Hatfield 1 in a ten-week planned outage in the fall of 1997. Docket Item 430 ¶ 33. Hatfield 1 had experienced three forced outages in the previous three years caused by problems with the SSOHs. PTX 565 at AE_DUN_00412489; PTX 81. Allegheny replaced the SSOHs with redesigned headers of a stronger material. Docket Item 430 ¶ 35. The purpose of the project was to improve the availability and reliability of the Hatfield boilers; Allegheny expected that the new headers would "drastically increase Unit 1's reliability." PTX 723 at AE_HQ_00369760; PTX 215 at AE_DUN_00005313.

A header is a large cylinder that collects steam from the many tubes in a component, such as a superheater, and sends that steam in a single stream to the next component. T.T., Sept. 20, 2010, at 25:16-26:17. Each SSOH was sixty feet long and weighed 90,000 pounds. PTX 758 at AE_MIT00033387; T.T., Sept. 20, 2010, at 25:16-26:7, 35:10-35:18. The SSOH project

required cutting a hole in the roof of the building, and using a special crane to remove the old headers and install the new ones. T.T., Sept. 20, 2010, at 35:7-35:13. The project cost $2,513,016 and was accounted for as a capital expense. Docket Item 430 ¶¶ 37, 38.

d. Hatfield 2 Pendant Reheater PSD Project

In 1993, Allegheny replaced the entire pendant reheater and cross-over tubes at Hatfield 2 in a ten-week planned outage. Docket Item 430 ¶ 41. Problems with the pendant reheater had been causing one forced outage per year, and Allegheny expected an additional two outages per year in the future if the reheater were not replaced. PTX 715 at AE_DUN_00194043. Allegheny concluded that replacing the reheater would "improve the availability" of the Hatfield 2 boiler because there would be no or few forced outages related to the new reheater during its 30 year life span. PTX 715 at AE_DUN_00194035, 042. Allegheny expected that Hatfield 2 would generate more electricity after a new reheater was installed because the unit would not be shut down for a 72-hour forced outage each year caused by the reheater. *Id.* at AE_DUN_00194035. Allegheny expected that the additional generation would save it $13,013,249 in replacement energy costs. PTX 715 at AE_DUN_00194045.

The pendant reheater consisted of 125 separate pendants, or assemblies of tubes suspended from a header near the top of the boiler and running the width of the boiler. Each assembly weighed several thousand pounds, was approximately 40 feet high and twenty feet long and contained 700 feet of tubing; the entire reheater contained 17 miles of tubing. T.T., Sept, 20, 2010, at 13:3-14:1, 15:06-15:10, 21:24-22:2.

For eight weeks, eighty people employed by outside contractors worked six days a week in two ten-hour shifts to remove the old and install the new reheater. T.T., Sept. 20, 2010, at 23:22-24:07. A total of 2,265 individual welds were required to install the tubing of the new

reheater. PTX 730 at AE_HF_00039483-000039492. The project cost $5,692,777 and was accounted for as a capital expense. Docket Item 430 ¶¶ 44, 45. Allegheny had never before replaced the entire pendant reheater and all the cross-over tubes since the unit began operating 23 years earlier. Docket Item 430 ¶ 19, 47.

e. Mitchell 3 Lower Slope Replacement PSD Project

Allegheny replaced a section of the Mitchell 3 lower slopes during a twelve-week planned outage in 1994. Docket Item 430 ¶ 67. In the five years before the project was recommended, there were an average of 3.8 tube leaks per year in that section of the lower slope. Allegheny expected a further decline in availability unless sections of the lower slopes were replaced. PTX 293 at AE_DUN_00191935. The project's purpose was to "improve plant availability," and to enable Mitchell 3 to operate better in the future than it had in the past. PTX 706 at R-3 06901; T.T., Sept. 23, 2010, at 128:22- 129:3.

Outside contractors performed the project, which cost $626,402 and was accounted for as a capital expense. Docket Item 430 ¶¶ 69, 70; PTX 706. This was the first time Allegheny had done a project of this magnitude on the Mitchell 3 lower slope since the unit began operating thirty-one years earlier. T.T., Sept. 20, 2010, at 55:12-15; Docket Item 430 ¶ 63.

C. Allegheny Should Have Expected That the Projects Would Result in Emissions Increases of at Least 40 Tons Per Year

Because Allegheny knew that its generating units were so large that they produced tons of pollutants in just a few hours of operation, and because it expected the PSD Projects to increase the availability of those units by seventy or more hours each year, Allegheny was on notice that the PSD Projects would almost certainly increase emissions by more than 40 tons per year. When Allegheny replaced deteriorated components at the Armstrong, Hatfield's Ferry and Mitchell 3 units, it expected the availability of these units to increase by 70 or more hours each

year – the number of hours of forced outage that the components had caused in the past. T.T., Sept. 20, 2010, at 72:13-23. This expectation of increased availability is the justification in every economic analysis for recommending the expenditure of millions of dollars on the projects. PTX 704 at AE_DUN_00005220, PTX 715 at AE_DUN_00194035, PTX 723 atAE_HQ_00369760, PTX 706 at R-3 06901. Stated simply, when new components are installed, the units have fewer forced outages, they generate more electricity, and Allegheny spends less money on replacement power. That is the predominant financial benefit of replacing deteriorated components. T.T., Sept. 20, 2010, at 21:4-23.

Allegheny also knew that the expected availability increases from the projects were all much greater than the number of hours its units had to operate to emit 40 tons or more of SO_2 and NO_x. As an example, while Allegheny expected each Hatfield lower slope project to increase availability by 256 hours per year, each Hatfield unit needed only approximately seven hours of operation to emit 40 tons of SO_2. PTX 1309-21, PTX 1309-22, PTX 1309-24. Thus, to generate a 40-ton increase in SO_2 emissions from one of the Hatfield's Ferry lower slope projects, Allegheny would only have had to use the unit less than three percent of the 256 hours it expected the availability to increase.

In the 1990s, however, Allegheny used its Armstrong, Hatfield's Ferry and Mitchell 3 units most of the time they were available. Allegheny used the Hatfield's Ferry units about 75-85 percent of the time they were available, not 3 percent. PTX 1987, PTX 1997, PTX 2005. Allegheny used the Armstrong units approximately 90 percent of the time they were available and used Mitchell 3 about 69 percent of the time it was available. PTX 1969, PTX 1977, PTX 2012. So based on Allegheny's own project economic analyses and unit performance data, Allegheny was on notice that, as a result of the PSD Projects, it would almost certainly increase

the amount of time it would use its generating units by far more than the few hours necessary to generate 40 tons per year of SO_2 and NO_x.

D. Plaintiffs' Projections of Future Emissions

At trial, plaintiffs presented expert analysis that confirmed that Allegheny should have expected the projects at issue to increase emissions by more than 40 tons per year. The starting point for that analysis was determining the extent to which Allegheny should reasonably have expected availability of the generating units to increase as a result of the projects. Robert Koppe, plaintiffs' expert witness on power plant performance, made those determinations. To do so, he reviewed Allegheny's submissions to the industry-wide database known as the Generation Availability Data System, or "GADS", which utilities, including Allegheny, rely upon to improve the availability of their generating units by tracking which components are causing forced outages. T.T., Sept. 20, 2010, at 93:17-94:7. Mr. Koppe was one of the principal architects of the GADS database and has spent 35 years performing availability analyses for dozens of utilities and others using the same methodology as he used in this case. T.T., Sept. 14, 2010, at 195:7-196:18; T.T., Sept. 20, 2010, at 93:17-94:7.

Allegheny's GADS submissions record every forced outage at its generating units, the length of the outage, and its cause. T.T., Sept. 23, 2010, at 19:16-22:10; DTX 1399. Thus, by reviewing Allegheny's GADS data and other information to determine which outages at a generating unit had been caused by a component that Allegheny was replacing and upgrading in a particular project, Mr. Koppe determined how many additional hours of availability Allegheny should have expected to recover as a result of that project. T.T., Sept. 20, 2010, at 93:7-97:18; PTX 77 - PTX 87.

Using Mr. Koppe's estimates of the change in availability, if any, from the PSD Projects, plaintiffs' expert Dr. Richard Rosen then performed calculations to determine whether the PSD Projects should have been expected to increase emissions. Those calculations are referred to as "actual to projected future actual" calculations. T.T., Sept. 21, 2010, at 16:25-17:12. To perform those calculations, he projected the emissions at each unit in the two years after each project and compared them to the actual emissions from that unit in a two-year baseline period before the project. T.T., Sept. 21, 2010, at 47:17-21. As the baseline period, Dr. Rosen selected the twenty-four months during the five years before the project in which the average level of generation most closely matched the average level of generation over the entire five-year period. T.T., Sept. 21, 2010, 12:14-18, 51:14-54:14.

For both the baseline and post-project periods, Dr. Rosen calculated emissions by looking at the various factors that influence the amount of emissions generated by a coal-fired power plant. T.T., Sept. 21, 2010, at 19:20-20:22; PTX 2132 (d). One factor was the intensity with which the unit is used or its "capacity factor." A unit's capacity factor is expressed as the percentage of the possible total output of electricity from the unit that the unit actually generates. T.T., Sept. 21, 2010, at 20:5-9, 22:19-23:3. Thus, a unit with an annual 70 percent capacity factor has generated 70 percent of the electricity the unit could have generated if it had operated at maximum capacity one hundred percent of the time during the year. T.T., Sept. 21, 2010, at 22:19-23:8. The capacity factor depends on two factors: first, the percentage of time the unit is available to operate, known as its equivalent availability factor, or "EAF," and second, the percentage of time the unit is actually operated when it is available, known as its utilization factor or "UF." T.T., Sept. 21, 2010, at 42:8-17, 45:22-46:3; PTX 2145 (d).

The other factors relating to power-plant emissions that Dr. Rosen considered are: the unit's size, or its "capacity"; its efficiency or "heat rate"; the energy content of the coal being burned, or the coal's "heat content"; and the emissions factors, which represent the amount of pollution generated per ton of coal burned. T.T., Sept. 21, 2010, at 20:5-22, 22:19-23:8, 24:18-25:1, 27:23-28:18. Dr. Rosen embodied these factors in five mathematical equations that each represent a standard, undisputed relationship governing power-plant operations. T.T., Sept. 21, 2010, at 21:15-24, 23:20-24:8, 29:8-13, 45:2-21; PTX 2133 (d), PTX 2145 (step 1), PTX 2134 – 2137 (steps 2-5); PTX 2147 (five equations combined) .

In his calculation of emissions during the pre-project baseline period, Dr. Rosen obtained the information about the relevant factors from Allegheny's records. T.T., Sept. 21, 2010, at 58:17-25, 72:6-24, 84:5-85:4. In his calculation of projected emissions during the two years after the projects, Dr. Rosen derived each unit's availability from Mr. Koppe's conclusions about expected availability increases resulting from the projects. T.T., Sept. 21, 2010, at 59:1-12.

Dr. Rosen held the other factors in his calculation constant for several reasons. First, for some of the factors, such as the heat content or sulfur content of coal, Dr. Rosen found no evidence in his review of Allegheny's voluminous document production that Allegheny had expected any change in those factors before undertaking the projects. T.T., Sept. 21, 2010, at 87:21-88:5. For others, such as unit capacity and heat rate, he relied on Mr. Koppe's expert opinion that these factors would remain the same after the projects. T.T., Sept. 21, 2010, at 84:5:-85:4. In addition, counsel informed Dr. Rosen that he should not incorporate reductions in NO_x emissions resulting from Allegheny's installation of low NO_x burners in his calculations because the regulations did not permit Allegheny to receive credit for those NO_x reductions in PSD emissions projections. T.T., Sept. 21, 2010, at 11:17-24, 11:25-12:5, 88:6-89:19.

When Dr. Rosen subtracted the actual baseline emissions from the projected post-project emissions, he concluded that Allegheny should have expected at least a 40 ton per year increase in SO_2 and NO_x emissions from each of the PSD Projects that remain in the case, except with respect to SO_2 emissions from the Mitchell 3 project. As explained in Argument section IV.C.3.c below, Dr. Rosen's calculations represent reasonable projections of the effect of the PSD Projects on emissions for the purpose of evaluating PSD liability.

Dr. Rosen also performed a separate set of emissions projections known as potential-to-emit calculations for the Armstrong Reconstruction Projects. T.T., Sept. 21, 2010, at 105:18-106:7. For those analyses he calculated the maximum amount the Armstrong units could emit – operating at 100 percent capacity factor – after the project, and subtracted from that the emissions from the unit in the 24-month pre-project baseline period. T.T., Sept. 21, 2010, at 105:18-107:10. Based on those calculations, he concluded that Allegheny should have expected at least a 40 ton per year increase in SO_2 and NO_x. As explained in Argument section V.C.4 below, those potential-to-emit calculations represent reasonable projections of the effects of the Reconstruction Projects on emissions for the purpose of evaluating nonattainment NSR liability.

V. ALLEGHENY'S RACT COMPLIANCE PROJECTS

In the 1993-1995 period, Allegheny installed pollution control equipment to meet the RACT requirements (the "RACT projects") at the Armstrong, Hatfield's Ferry and Mitchell 3 units. At Hatfield's Ferry, Allegheny installed low-NO_x burners at unit 2 in a September-December 1993 outage, at unit 1 in an October-November 1994 outage, and at unit 3 in a February-May 1995 outage. Docket Item 430 ¶¶ 23, 24, 25. According to Allegheny, installation of low-NO_x burners at Hatfield's Ferry 2 reduced emissions by approximately 57

percent. PTX 1920 at AE_DUN_00047451 (noting reduction from 1.28 to 0.52 lb./million BTU).

At Armstrong, Allegheny installed low-NO_x burners plus an additional technology, overfire air, at the two units in a February-October 1995 outage and an April-December 1994[8] outage. PTX 1919 at AE_DUN_00047428, 00047429. At Mitchell 3, in an October-December 1995 outage, Allegheny also installed low-NO_x burners and overfire air. *See, e.g.*, PTX 1919 at AE_DUN_00047431. According to Allegheny, installation of this technology at Mitchell 3 reduced emissions by approximately 46 percent. PTX 1920 at AE_DUN_00047452 (noting reduction from 0.67 lb./million BTU to 0.36 lb./million BTU).

As noted in Background and Facts section II.E above, RACT is less stringent than BACT, and Allegheny's RACT controls would not have satisfied BACT. For example, in August 1995, PA DEP set BACT for NO_x emissions for a pulverized bituminous coal unit at 0.15 lb./million BTU, a limit much more stringent than the 0.45 to 0.58 lb./million BTU RACT limits PA DEP set in June 1995 for the Allegheny pulverized bituminous coal units. *Compare* PTX 1921 *with* PTX 1916 at AE_HQ_00595046, ¶ 7; PTX 1917 at AE_HQ_00595178, ¶ 5; PTX 1918 at AE_HQ_006078, ¶ 16.

VI. ALLEGHENY'S TITLE V APPLICATIONS AND PERMITS

The Armstrong, Hatfield's Ferry and Mitchell power stations are major stationary sources and, as such, were subject to Title V permitting requirements. Docket Item 430 ¶ 5 (stipulation that these power stations were "major stationary sources"). Allegheny submitted Title V permit applications to PA DEP for these power stations in July 1995. *See* PTX 1210 (Armstrong); PTX 1207 (Hatfield's Ferry); PTX 1213 (Mitchell). None of these permit applications addressed

the Reconstruction or PSD Projects or identified as applicable requirements any BACT, NSPS, nonattainment NSR or BAT emissions limitations that would have been required as a result of those projects. *See* PTX 1210 *passim*; PTX 1207 *passim*; PTX 1213 *passim*. Allegheny did not subsequently notify PA DEP about those projects.

PA DEP issued the Title V permits for the three power stations in 2001 for Armstrong and Hatfield's Ferry and in 2002 for Mitchell. PTX 1203 (November 29, 2001 Hatfield's Ferry permit); PTX 1209 (July 31, 2001 Armstrong permit); PTX 1212 (March 26, 2002 Mitchell permit). The permits did not incorporate as applicable requirements any BACT, NSPS, nonattainment NSR or BAT emissions limitations that would have been required as a result of the Reconstruction or PSD Projects.

ARGUMENT

Based on the legal standards set out in the statutes, regulations and guidance, and the facts presented at trial, Allegheny is liable for violations of the federal and Pennsylvania NSPS, PSD and Title V programs and the Pennsylvania nonattainment NSR and plan approval/BAT programs. In an attempt to streamline briefing, plaintiffs have attempted, to the extent reasonably possible, to address Allegheny's defenses and counterarguments in advance of the filing of Allegheny's post-trial brief in February 2011.

On the factual matters before the Court, the standard of proof in this civil action is preponderance of the evidence. *See, e.g.*, *Grogan v. Garner*, 498 U.S. 279, 286 (1991) (preponderance of the evidence standard is presumed to apply in civil actions in which there are no particularly important individual rights or interests at stake) (citing *Herman & MacLean v.*

[8] Allegheny installed the overfire air, or "OFA," for unit 2 as a follow-up part of its RACT compliance in a later September 1995 outage. PTX 1919 at AE_DUN_0047428.

Huddleston, 459 U.S. 375, 389-390 (1979)); *United States v. Ohio Edison Co.*, 276 F. Supp.2d 829, 885 (S.D. Ohio 2003) (plaintiffs had proven their claims by a preponderance of the evidence). As explained above and below, plaintiffs' proof at trial exceeds that standard.

I. <u>THIS COURT HAS JURISDICTION AND IS A PROPER VENUE</u>

This Court has jurisdiction over the subject matter of this action pursuant to 42 U.S.C. §§ 7604(a), and 28 U.S.C. §§ 1331 and 1367. Clean Air Act section 304(a), 42 U.S.C. § 7604(a), provides that the district courts of the United States have jurisdiction, without regard to the amount in controversy or the citizenship of the parties, to hear citizen suits alleging (a) violations of emissions standards and limitations or (b) unlawful failure to obtain a PSD or nonattainment NSR permit before modifying a major emitting facility. Such citizen suits may be brought by "any person" against "any person." 42 U.S.C. § 7604(a).

If the claim concerns a violation of an emissions standard or limitation, the plaintiff must provide notice of the claim at least 60 days before filing suit to the alleged violator, the EPA administrator, and to the state in which the violation occurs. 42 U.S.C. § 7604(b)(1)(A). If the claim concerns failure to obtain a PSD or nonattainment NSR preconstruction permit, the statute does not require such notice. *See* 42 U.S.C. § 7604(b) *passim* (nowhere requiring notice for claims under 42 U.S.C. § 7604(a)(3)).

Plaintiffs meet the requirements for subject-matter jurisdiction under 42 U.S.C. § 7604. As states, the plaintiffs are "persons" under the Clean Air Act. 42 U.S.C. § 7602(e). Allegheny has stipulated that the defendants are "persons" under the Clean Air Act. Docket Item 430 ¶ 3. To the extent plaintiffs' federal-law claims assert violations of emissions standards or limitations, plaintiffs provided notice of those claims either (a) 60 days before filing their initial

complaint, for claims included in that complaint, or (b) 60 days before filing their amended complaint, for claims added in that amendment. *See* PTX 17; PTX 18; PTX 19.

Allegheny contends that the Court does not have subject-matter jurisdiction over claims for which it did not receive adequate notice. PTX 2 ¶ 20. Allegheny has thus far identified only two claims, regarding the Mitchell 3 PSD Project, for which it contends it did not receive such notice. This Court has already held that Allegheny received adequate notice on those claims, to the extent any was legally required. Docket Item 45 at 16-18, *as adopted by* Docket Item 50. This Court also has jurisdiction over the plaintiffs' federal-law claims under the general federal question statute, 28 U.S.C. § 1331.

Under 28 U.S.C. § 1367(a), this Court has supplemental jurisdiction over "all other claims that are so related to the claims in the action within such original jurisdiction that they form part of the same case or controversy under Article III of the United States Constitution." Because PA DEP's state-law claims in all cases arise from the same factual events as the plaintiffs' federal-law claims, and in most cases mirror the plaintiffs' federal-law claims, the Court has supplemental jurisdiction over those state-law claims.

With respect to all claims, venue is proper in this District pursuant to 28 U.S.C. §§ 1391(b) because all defendants resided in this District when the action was filed in June 2005, a substantial part, if not all of the events or omissions giving rise to the claim occurred in this District and a substantial part of the property that is the subject of the action is located in this District. Allegheny admits that venue in this District is proper. PTX 2 ¶ 21.

II. ALLEGHENY IS LIABLE FOR VIOLATING THE NEW SOURCE PERFORMANCE STANDARDS UNDER FEDERAL AND PENNSYLVANIA LAW BY RECONSTRUCTION OF THE ARMSTRONG BOILERS (CLAIM NOS. 4-5, 10-11)

A. Summary of Argument

In 1994 and 1995, Allegheny undertook, in its own words, "a total rebuild of the boilers" at Armstrong 1 and 2: it replaced virtually every component in each boiler and improved the boilers' design, materials and equipment. Armstrong 1 and 2 boilers have been in violation of the NSPS emission limits since that time.

NSPS emissions limits apply to reconstructed facilities. Under the regulations, "reconstruction" occurs if: (1) work done on the unit is so extensive that the work's cost exceeds 50 percent of the cost of a "comparable entirely new facility," and (2) it is technologically and economically feasible to meet the NSPS emissions limits at the facility. The law and evidence support plaintiffs on both of these issues.

On the first issue, plaintiffs have proven, using three expert methodologies, that the cost of the components replaced in each boiler exceeded the 50 percent threshold by many millions of dollars. The 2010 opinion from Allegheny's trial expert that these projects cost less than 50 percent fails to conform to the correct legal standard, relies on an unreliable methodology, and is not credible in light of Allegheny's 1994 conclusion that the projects were a "total rebuild."

The technological and economic feasibility of meeting the standards is presumed as a matter of law. Allegheny has not rebutted the presumption. In fact, the evidence in the record shows that complying with NSPS at Armstrong is both technologically feasible and much less expensive than EPA's economic feasibility threshold.

Because plaintiffs have established these elements and the remaining undisputed elements of their claims, Allegheny is liable for violating NSPS at Armstrong 1 and 2.

B. The Legal Standard

In Claims 4-5 and 10-11 the plaintiffs assert that Allegheny's total rehabilitation of the Armstrong 1 and 2 boilers constituted "reconstruction" that subjected the boilers to the federal NSPS for steam generating units ("NSPS Claims"). The NSPS regulations for electric utility generating units, Subpart Da, were promulgated in 1979. 44 Fed. Reg. 33580, 33612–24 (June 11, 1979) [PTX 2202 (d)]. Electric utility steam generating units with heat input of at least 73 MW, which began construction after September 18, 1978, are subject to its provisions. 40 C.F.R. § 60.40Da(a)(1). In 1979, Pennsylvania adopted these federal NSPS regulations by incorporating them by reference into the Commonwealth's regulations. 25 Pa. Code §§ 122.1, 122.3; 9 Pa. Bull. 1447, 1451, 1534 (1979).

Covered facilities become subject to NSPS emissions limits if they are "reconstructed." NSPS regulations define reconstruction as follows:

> 60.15 Reconstruction.
>
> (a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.
>
> (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

40 C.F.R. § 60.15(a), (b) [PTX 2219 (d)]. It is unlawful for a source subject to NSPS emissions limits to emit pollution in excess of those limits. 42 U.S.C. § 7411(e).

Accordingly, there are four elements to establish liability on an NSPS reconstruction claim: (1) the facility is a covered electric steam generating unit; (2) the capital cost of the

project at issue exceeds 50 percent of the capital cost of a "comparable entirely new facility"; (3) it is technologically and economically feasible to meet the NSPS emissions limitations at the facility, and (4) after the reconstruction, the facility has failed to meet the NSPS emissions limits.

C. Several Elements and Aspects of the NSPS Reconstruction Analysis for Armstrong 1 and 2 Are Not In Dispute

There is no dispute that several elements of plaintiffs' NSPS claims have been met.

1. The Armstrong Boilers Meet NSPS Applicability Requirements

The parties have stipulated that the Armstrong 1 and 2 boilers are "electric utility steam-generating units" as that term is defined in the federal regulations. Docket Item 430 ¶ 11. Allegheny has admitted that each boiler has a nameplate heat output rating of 163 MW. PTX 1 ¶ 126, PTX 2 ¶ 126. Thus, the heat input is greater than 73 MW, which is the threshold for potential NSPS applicability for electric utility steam boilers. 40 C.F.R. § 60.40Da(a)(1).

There also is no dispute that the Reconstruction Projects occurred after September 18, 1978, during major outages in 1995 and 1994. Docket Item No. 431 ¶¶ 3, 4. Accordingly, the Armstrong boilers are subject to the NSPS regulations for electric utility steam generating units.

2. The Scope of the "Affected Facility" Under NSPS

Generally speaking, for NSPS 'sources' are entire plants, while 'facilities' are identifiable pieces of process equipment or individual components which when taken together would comprise a source. 40 Fed. Reg. 58415, 58416 (Dec. 16, 1975) (1st Column) [PTX 2201 (d)]. In this litigation, the "affected facility" is a steam generating unit, which means a furnace, boiler or other device used for the purpose of producing steam. 40 C.F.R. § 60.41Da. The regulations do not further specify what is included in a steam generating unit, but the U.S Environmental Protection Agency ("EPA") provided guidance on the extent of the "affected facility" in a 1986 memorandum. PTX 137 ("Rasnic Memorandum"). In the Rasnic

Memorandum, EPA concluded that "affected facility" for an electric utility steam generating unit consists of all components between "the coal bunkers and ends at the stack breeching." T.T., Sept. 13, 2010, at 66:3-67:14; PTX 137 at 2. The extent of the "affected facility" is illustrated on a sketch that is Attachment C to the Rasnic Memorandum. PTX 137 at Attachment C; T.T., Sept. 13, 2010, at 67:15–68:25. Both plaintiffs' and Allegheny's experts used this definition of "affected facility" in their analyses. T.T., Sept. 13, 2010, at 69:6-14; T.T., Sept. 28, 2010, at 85:19–86:7. Accordingly, plaintiffs and Allegheny agree about the scope of the "affected facility." T.T., Sept. 13, 2010, at 69:6-14.

3. Armstrong Reconstruction Projects' Scope and Cost

Allegheny does not dispute plaintiffs' description of the extent of work done during the Reconstruction Projects. T.T., Sept. 13, 2010, at 78:22–84:23 (Dr. Sahu's testimony describing components replaced and work done). Plaintiffs' understanding of the projects is based on Allegheny's documents and admissions. *See, e.g.*, PTX 356 (unit 1 completion report); PTX 828 (unit 1 recommendation memorandum); D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2007, at 67:16–71:4, 76:20–80:15.

The cost of the Reconstruction Projects also is not in dispute. Allegheny's expert accepted the costs of the projects as determined by plaintiffs' accounting expert, Hugh Larkin, C.P.A: unit 1: $52,431,805[9]; unit 2: $53,302,358. T.T., Sept. 28, 2010, at 83:6-11.

[9] One of Mr. Larkin's exhibits, PTX 906, contains a typographical error. On this document the cost of the new components for Unit 1 is identified as $52,780,917. In his October 2007 expert report, however, Mr. Larkin had reduced this figure to $52,431,805 to account for the subtraction of air compressor costs of $349,111, which Allegheny determined were not part of the boiler unit. PTX 907, PTX 908.

4. Allegheny's Non-Compliance with NSPS SO_2 Standard

The parties have also stipulated that since completing the Reconstruction Projects sulfur dioxide ("SO_2") emissions from each unit have continuously exceeded the NSPS SO_2 emission limit of 1.2 lb./million BTU. Docket Item 431 ¶¶ 1, 2. In fact, since the projects were completed, sulfur dioxide emissions at Armstrong 1 and 2 have typically exceeded that limit by 200 - 250 percent. T.T., Sept. 13, 2010, at 90:25-91:5; PTX 127 at 1-6.

D. The Evidence Demonstrates that Allegheny Violated NSPS by <u>Reconstructing the Armstrong Boilers</u>

1. Allegheny's Own Descriptions of the Armstrong Work Demonstrate That It Reconstructed the Affected Facilities

It is apparent from the description of the Armstrong work in Allegheny's own contemporary documents that the boilers were reconstructed. Allegheny described the work as "a total rebuild of the boilers." PTX 1222 at AE_DUN_00381331. Allegheny's completion memorandum described the "[d]emolition and complete removal of the No. 1 boiler and ash hopper with the exception of steam drum, downcomer feeder tubes and six downcomers," and complete demolition and removal of the No. 1 draft plant, and other demolitions and replacements. PTX 356 at R-3 22824-25. Dr. Sahu illustrated the extent of the demolition and replacement work described in Allegheny's documents at trial. He scratched off each component replaced by Allegheny on a schematic boiler diagram. T.T., Sept. 13, 2010, at 79:7–83:16. At the conclusion of this testimony, the entire diagram was obliterated, just as the actual Armstrong boilers were by the Reconstruction Projects. All of the tubes, burners, ducts and virtually all other items were removed and replaced.

The *only* boiler components left when the Reconstruction Projects were done were the steam drum, some downcomer feeder tubes and some downcomer tubes. T.T., Sept. 13, 2010, at

84:12-23. The pulverizers and some of the foundation also survived. The cost of the steam drum and downcomer equipment is $41,912, a trivial cost compared to the original cost of one of the boilers, approximately $51 million for unit 1 and $35 million for unit 2. D.T. (Dennis Herron 30(b)(6) witness on accounting issues), Aug. 15, 2007, at 239:10-242:6; PTX 906. Thus, to avoid NSPS reconstruction, the cost of the pulverizers and part of the foundation would have to exceed the cost of the entire rest of the boiler. This scenario is so unlikely that Allegheny did not advance it.

Moreover, comparing the boilers before and after the Reconstruction Projects shows that they were, in fact, reconstructed. EPA established the NSPS reconstruction standard to capture existing facilities that undergo such extensive component replacements that they no longer have the character of the existing facility, and are in essence "new." 40 Fed. Reg. 58416, 58417 (Dec. 16, 1975) (3d column) [PTX 2201 (d)]. That is what happened at Armstrong. In addition to replacing virtually every boiler component and upgrading boilers' design and materials, Allegheny changed the boiler's structural support system. In their original design, the boilers were supported from the bottom; however, as part of the Reconstruction Projects the support system was changed to support the boilers from the top. T.T., Sept. 13, 2010, at 79:12-20. Thus, because the boilers no longer "retained their character as existing facilities" after the Reconstruction Projects, they were reconstructed.

2. The Armstrong Boiler Projects' Cost Exceeds the NSPS Reconstruction Threshold Using "Comparable Entirely New Facilities" Based on the Armstrong 1 and 2 Boilers

Notwithstanding its own description of the projects as a "total rebuild," Allegheny does not agree that Armstrong 1 and 2 were "reconstructed" for purposes of NSPS applicability. But

plaintiffs' expert analyses confirm what Allegheny's own documents say: Allegheny replaced much more than 50 percent of the Armstrong boilers.

Subpart (b)(1) of the NSPS reconstruction definition, the 50 percent test, 40 C.F.R. § 60.15(b)(1) [PTX 2219(d)] can be conveniently expressed by the following mathematical equation ("Reconstruction Formula"):

$$\frac{\text{FIXED CAPITAL COST OF NEW COMPONENTS}}{\text{COST OF A COMPARABLE ENTIRELY NEW FACILITY}} = \text{x} \quad 100 \quad > \quad 50\%$$

T.T., Sept. 13, 2010, at 61:21-62:11 (Dr. Sahu). The parties disagree over the number in the denominator of this formula, the cost of a "comparable entirely new facility." *See, e.g.*, T.T., Sept. 28, 2010, at 83:14-17 (Mr. Golden). The record shows that plaintiffs' approaches to this issue are faithful to the language of the NSPS regulations, consistent with EPA guidance, require the fewest assumptions, and use an unquestionably comparable unit.

The best approach to determining the cost of a "comparable entirely new facility" begins with the Armstrong boilers themselves. Whether the Court looks at the original capital costs of the Armstrong affected facility or the costs escalated to 1994 and 1995 when the Reconstruction Projects occurred, the projects exceed the reconstruction threshold by a wide margin.

a. The Armstrong 1 and 2 Boilers Are "Comparable Facilities" for the NSPS Reconstruction Formula Denominator

The NSPS reconstruction formula denominator is "the cost of an entirely new comparable facility." 40 C.F.R. § 60.15(b)(1) [PTX 2219 (d)]. The regulations do not define an "entirely new comparable facility." Plaintiffs' expert, Dr. Ranajit Sahu, whom the Court accepted as an expert in power plant engineering, air pollution control and air quality permitting

and regulations,[10] determined that the Armstrong 1 and 2 boilers, with the components that had been installed or replaced as of the time just before Allegheny undertook the Reconstruction Projects, best represent "an entirely new comparable facility." Dr. Sahu based this conclusion on his experience, the words of the NSPS reconstruction regulation, EPA guidance interpreting reconstruction and the relevant facts. T.T., Sept. 13, 2010, at 69:22-76:1, 128:24-129:12.

i. Plain Language of the Definition

Dr. Sahu's "comparable facility" opinion flows from the plain meaning of the reconstruction definition. It is settled law that words in regulations should be accorded their common meaning if no special meaning has been assigned to them. *Lewis v. Atlas Van Lines, Inc.*, 542 F.3d 403, 409 (3d Cir. 2008); *Elliott Coal Mining Co. v. Director, Office of Workers' Compensation Program*, 17 F.3d 616, 629 (3d Cir. 1994).

"Comparable" is not defined in the NSPS regulations. 40 C.F.R. § 60.2 [PTX 2218 (d)]. However, the dictionary defines "comparable" as follows:

> *Comparable.* 1. Capable of or suitable for comparison 2. EQUIVALENT, SIMILAR (fabrics of ~ quality)

Webster's New Collegiate Dictionary 226 (1981) [PTX 2216 (d)] (typeface in original)). A closer match to the definition can hardly be imagined. There is no question that each of the Armstrong boilers was "equivalent" or "similar" to itself, making it comparable as required by the NSPS reconstruction definition. In colloquial terms, using the cost of the Armstrong boilers as the cost of "comparable" facilities, allows for a comparison of "apples to apples."

[10] T.T., Sept. 13, 2010, at 42:12-23.

ii. Consistent with EPA Interpretive Guidance

Dr. Sahu's "comparable" facility opinion also follows EPA's interpretation of the NSPS regulations. When interpreting regulations, courts rely upon formal and informal interpretations by the agency that promulgated the regulation. *Auer v. Robbins*, 519 U.S. 452, 461 (1997); *Soltane v. Department of Justice*, 381 F.3d 143, 148 (3d Cir. 2004). Applicability determinations in which EPA interprets and applies its regulations in response to questions from regulators and industry are among the documents that environmental professionals typically look to for guidance. T.T., Sept. 13, 2010, at 59:18-60:10. Dr. Sahu is familiar with EPA's applicability determinations through his work as an environmental professional. T.T., Sept. 13, 2010, at 72:12-73:17.

Dr. Sahu cited two relevant EPA applicability determinations. T.T., Sept. 13, 2010, at 73:16-74:12. These documents express EPA's longstanding guidance on determining a "comparable entirely new facility," an approach that was being applied in the mid-1990s when the Armstrong Reconstruction Projects were done. T.T., Sept. 13, 2010, at 73:7-13. In one, EPA concluded that a "'comparable entirely new facility' would consist of a new boiler with identical components to the repaired boiler." PTX 2158 (d) at 2. In the other, EPA stated that the "comparable entirely new facility is to be based on the turbine that was removed and replaced." PTX 2157 (d) at 5.

Consistent with this EPA guidance Dr. Sahu testified that "comparable" in the NSPS reconstruction definition means "having those pieces that are similar or identical to the piece that was being replaced." T.T., Sept. 13, 2010, at 72:1-11. He further explained that a "comparable" facility should be of the same size and of a design as close as possible to the facility being reconstructed. T.T., Sept. 13, 2010, at 133:13-19. The "comparable entirely new facility" also

should fulfill the same function and do it in the same way, because adding modern advances to the design departs from the understanding of "comparable." T.T., Sept. 13, 2010, at 136:19-23. Accordingly, by basing the "comparable" facility on the facilities being replaced, the Armstrong boilers, Dr. Sahu followed EPA's guidance.

iii. Giving Effect to All Words

Using the Armstrong boilers as "comparable entirely new facilities" gives effect to all of the words of the reconstruction definition. Regulations should be interpreted and applied to give meaning to all words and render no part superfluous. *Idahoan Fresh v. Advantage Produce, Inc.*, 157 F.3d 197, 202 (3d Cir. 1998). Dr. Sahu's approach strikes a balance between "comparable" and "entirely new," giving meaning to each.

Dr. Sahu was cognizant that all of the reconstruction regulation's words should be given effect. T.T., Sept. 13, 2010, at 135: 4-10. He explained that using a unit with a new design or a larger size would essentially throw the word "comparable" out of the analysis. T.T., Sept. 13, 2010, at 137:24-138:9. On the other hand, using the Armstrong boilers as the "comparable facilities" demonstrates the "proper weighting of comparable and new, and not reading either one of them out of the definition." T.T., Sept. 13, 2010, at 138:6-9. Using the Armstrong boilers implements the "comparable" requirement for the reasons discussed above. It also gives meaning to the "entirely new" requirement. It was important to Dr. Sahu that detailed cost records for the Armstrong boiler were available. T.T., Sept. 13, 2010, at 74:13-23, 75:21-76:7. These costs reflect each boiler and its components in their new, pristine condition, when Allegheny initially installed them, rather than in their old and degraded condition[11] prior to being

[11] *See e.g.* PTX 828 at R-3 22641- 642 ("[t]he attached synopsis of individual components and associated problems vividly depict the ongoing deterioration of this boiler and suggests a continued and increased degradation of individual components")

replaced in 1994 and 1995. *Id.* Dr. Sahu's interpretation thus gives meaning to both "comparable" and "entirely new."

iv. Fewest Assumptions

The best approach to determine the "cost of an entirely new comparable facility" is the one that requires the fewest assumptions. T.T., Sept. 13, 2010, at 138:24-129:9. Minimizing or eliminating the need for assumptions minimizes or eliminates concerns about whether data developed is "comparable." The design of the Armstrong boilers and the specific components in each boiler are known; the original costs associated with the Armstrong boilers are also known. T.T., Sept. 13, 2010, at 74:13-23, 129:10-18. Thus, using the then-existing boilers as the "comparable" facilities takes the "guesswork" out of evaluating if the facility is "comparable," because the Armstrong boilers are comparable to themselves. T.T., Sept. 13, 2010, at 129:10-18.

The foregoing shows that Dr. Sahu's opinion that the Armstrong 1 and 2 boilers are the "comparable" facilities is well supported and consistent with the language of the regulations, EPA guidance and sound technical judgment. Accordingly, those boilers should be accepted as "comparable" facilities for NSPS reconstruction purposes.

b. Using Either Original Costs or Escalated Costs, the Armstrong Boiler Projects Exceed the NSPS Reconstruction Threshold

Plaintiffs' accounting expert, Hugh Larkin,[12] examined whether the costs of the Armstrong Reconstruction Projects exceeded the 50 percent reconstruction threshold in two ways: using original cost information for the boilers, and using original costs escalated to 1994 and 1995, the years of the projects. Using either approach (as well a third approach described in

[12] Mr. Larkin was accepted without objection as an expert in utility accounting and utility cost analysis. T.T., Sept. 13, 2010, at 180:6-11.

the next section) the result is the same: the Armstrong boilers were "reconstructed" and have been subject to NSPS emissions control requirements since the mid-1990s.

i. Using Original Costs of the Armstrong Boilers, the Boiler Projects Exceed the Reconstruction Threshold

Mr. Larkin, calculated the cost of a comparable entirely new facility using the Armstrong boilers' original cost basis ("original cost"). Original cost basis is the initial cost of the unit adjusted for the cost of components removed (i.e. retired), and components added. T.T., Sept. 13, 2010, at 184:19-185:5. Using original costs to determine NSPS applicability is appropriate.

EPA guidance interpreting the NSPS regulations supports using original costs. In a 1989 letter to Wisconsin Electric Power, EPA stated that the original cost of the affected unit should be used to determine capital cost for NSPS applicability:

> [I]t is more *appropriate to utilize the original basis* of each affected facility (as adjusted to reflect past capital improvements), expressed in nominal dollars, rather than the updated basis expressed in current dollars, in determining NSPS applicability.

DTX 134 (d) at 4 (emphasis added). EPA further explained:

> The effect of using original basis is that the greater the age of an affected facility, the more likely it is that a given investment resulting in increased production will be deemed a capital expenditure and trigger NSPS. This is consistent with Congress' intent in adopting new source performance standards.

Id. at 5. Thus, using original costs fosters Congress' intent, when it created NSPS, of replacing old polluting units with newer cleaner ones. *See also* T.T., Sept. 13, 2010, at 199:16-200:9 (Mr. Larkin testifying that using inflated costs, rather than original costs, would mean that "you'd never be updating any of this equipment and therefore would interfere with attaining the goal of the statute to "make sure that these older facilities have pollution control equipment").

As a practical matter, accurate original cost information was available for Armstrong 1 and 2 in a 1993 report filed by Allegheny with the Pennsylvania Public Utility Commission titled "Valuation of Electric Plant in Service" ("Plant Valuation Report"). PTX 904 at AE_HQ_00382230. These figures are actual costs, with no speculation or assumptions needed.

Mr. Larkin determined the original cost basis of Armstrong 1 and 2 from the Plant Valuation Report. The Report sets forth the original cost of the Armstrong units as of June 30, 1993, segregated into five account categories established by the Federal Energy Regulatory Commission ("FERC"). PTX 904 at 2; T.T., Sept. 13, 2010, at 185:6-186:15; *see also id.* at 183:10-18 (describing the FERC categories). Electric public utilities like Allegheny that are within FERC's jurisdiction are required to maintain their books and records in accordance with FERC's Uniform System of Accounts ("USOA"). T.T. Sept. 13, 2010, at 183:19-184:13. The USOA provides basic descriptions of accounts relevant to power plant accounting. *Id*. The five USOA accounts listed in the Plant Valuation Report are account nos. 311, 312, 314, 315, and 316. T.T., Sept. 13, 2010, at 183:10 - 18. The most important of these for this litigation is Account No. 312, which consists of boiler plant equipment. *See* T.T., Sept. 13, 2010, at 183:15. As seen from the Plant Valuation Report, the majority of costs associated with Armstrong units 1 and 2 are in Account No. 312. PTX 904 at 2. Mr. Larkin did not include costs in Account No. 314 for turbogenerator units, because such equipment is not part of the boiler unit. PTX 906. For the remaining USOA accounts (nos. 311, 312, 315, and 316[13]), because Mr. Larkin had no information to determine the amount of costs in those accounts that are "in" the affected

[13] Account no. 311 is structures and improvements, account no. 315 is accessory electric equipment, and account no. 316 is miscellaneous power plant equipment. T.T, Sept. 13, 2010, at 183:10–18.

facilities, he included all costs in those accounts related to the Armstrong 1 and 2 units. T.T., Sept. 13, 2010, at 186:9-18.

Mr. Larkin testified that the "cost of a comparable entirely new" facility for Unit 1 is $50,921,213, and for Unit 2 the cost is $ 34,819,598. T.T., Sept. 13, 2010, at 189:2-8; PTX 906, 907, 908. As noted in Argument section II.C.3 above, the capital cost of the components replaced during the Reconstruction Projects was: Unit 1: $52,431,805; Unit 2: $53,302,358.

Applying the Reconstruction Formula using these values shows that the Reconstruction Projects exceeded the reconstruction threshold for both units:

$$\text{Unit 1: } \frac{\$\ 52{,}431{,}805}{\$\ 50{,}921{,}213} = 103\%$$

$$\text{Unit 2: } \frac{\$\ 53{,}302{,}358}{\$\ 34{,}819{,}698} = 153\%$$

T.T., Sept. 13, 2010, at 189:9-12; PTX 906. Thus, the NSPS reconstruction threshold is exceeded for each Armstrong unit by a wide margin: for unit 1 by $ 27,320,311 and for unit 2 by $ 35,892,559. PTX 906.

Mr. Larkin's original basis calculations reflect some conservative choices, which favor Allegheny's position by inflating the Reconstruction Formula's denominator. For example, costs were not apportioned. All costs for any FERC account that was likely even partially "in" the affected facilities were included in the denominator. T.T., Sept. 13, 2010, at 186:9-18, 189:25-190:1; PTX 906.

Accordingly, plaintiffs properly used original costs for the Armstrong boilers to determine the cost of a "comparable entirely new facility." The Armstrong Reconstruction Projects exceed the NSPS reconstruction threshold at each unit by a wide margin.

ii. Using Escalated Capital Costs of the Armstrong Boilers, the Reconstruction Projects Exceed the Reconstruction Threshold

Mr. Larkin also evaluated NSPS reconstruction by an alternative approach, using Armstrong 1 and 2 original costs escalated to 1994 and 1995 dollars when the projects occurred. This evaluation, like the original cost analysis, shows that the Reconstruction Projects exceeded the reconstruction threshold by a wide margin.

Mr. Larkin escalated the "comparable facility" costs for the Armstrong boilers using the Handy-Whitman Index ("Handy-Whitman" or "Index").[14] T.T., Sept. 13, 2010, at 190:25-191:4. Handy-Whitman has been published since 1924, and is the only index tailored to the utility industry. The Index is used by a wide range of entities including the utility companies, regulatory bodies, equipment manufacturers and insurance companies. PTX 921 at iii, iv. Handy-Whitman provides cost escalation factors for the whole power plant, and for specific FERC account codes. PTX 922 at E-1-1 through E-1-8. The Index is updated annually using data from many sources. PTX 921 at iii. The Index also includes separate geographic entries that reflect regional cost differences. T.T., Sept. 13, 2010, at 120:7-10; PTX 921 at iv.

Dr. Sahu and Mr. Larkin testified that Handy-Whitman is a well established and commonly accepted tool among professionals for translating utility industry costs over time. T.T., Sept. 13, 2010, at 120:11-13, 191:5-14. Mr. Larkin has used Handy-Whitman to translate costs over time for public utility commission proceedings. T.T., Sept. 13, 2010, at 191:15-21. Allegheny has used Handy-Whitman to translate equipment costs over lengthy periods of time

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[14] Allegheny has objected to admission of sections of Handy-Whitman documents, PTX-921 and PTX 922, as hearsay. Plaintiffs have opposed this objection, asserting that Handy-Whitman is a highly reliable compilation that is used by a segment of the public, and properly admissible. Even if not admissible, however, Mr. Larkin, as an expert, can rely on it since it is routinely used in power plant accounting. T.T., Sept. 13, 2010, at 191:5-14.

up to 42 years, which is longer than the period over which Mr. Larkin translated the Armstrong units' costs. T.T, Sept. 13, 2010, at 191:22-195:2; PTX 1881 at 5, PTX 1883, PTX 1884.

Mr. Larkin applied the appropriate Handy-Whitman cost index factors to the original capital cost of the units and to the cost of subsequent capital additions to escalate those original costs to 1995 (unit 1) or 1994 (unit 2) dollars. T.T, Sept. 13, 2010, at 195:3-10, 196:3-25; PTX 915-917 (unit 1), PTX 918-920 (unit 2). In his escalated cost analysis, Mr. Larkin also adjusted the capital costs to reflect the portion of each FERC account that is "in" each "affected facility." He used a document supplied by Allegheny to plaintiffs, in which Allegheny admitted the percentage of capital cost in each Armstrong affected facility by FERC account. T.T., Sept. 13, 2010, at 189:23-190:15; PTX 899 at 3.

For unit 1, Mr. Larkin calculated the "cost of a comparable entirely new" facility escalated to 1995 dollars as $85,861,497, and for unit 2, he calculated the cost escalated to 1994 dollars as $74,044,895.[15] T.T., Sept. 13, 2010, at 197:1-198:12; PTX 908. The capital cost of the components replaced during the Reconstruction Projects is unchanged: unit 1: $52,431,805; unit 2: $53,302,358. *See* Argument Section II.C.3 above.

Applying the Reconstruction Formula using escalated original costs yields the following results:[16]

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[15] In his testimony, Mr. Larkin stated lower costs for units 1 and 2 because he read the cost before adding in the cost of low NO_x burners and overfire air. *See* PTX 908.

[16] Mr. Larkin testified that he made a minor mathematical error in calculating the percentage on PTX 908. He corrected the error in testimony. T.T., Sept. 14, 2010, at 23:11-22.

Unit 1:	$\frac{\$ 52,431,805}{\$ 85,861,497}$	x	100	=	64.6 %
Unit 2:	$\frac{\$ 53,302,358}{\$ 74,044,895}$	x	100	=	73.9%

T.T., Sept. 13, 2010, at 197:1-198:12; T.T., Sept. 14, 2010, at 23:6-22; PTX 908. Thus, the 50 percent reconstruction threshold is exceeded for each Armstrong unit by a wide margin. For unit 1 the standard is exceeded by $ 9,501,000, and for unit 2, by $6,280,000. PTX 908. Accordingly, plaintiffs' alternative method also shows that the Reconstruction Projects' costs exceed the NSPS reconstruction threshold.

3. A Third Method Also Shows That the Armstrong Reconstruction Projects Exceeded the 50 Percent Threshold

Dr. Sahu also estimated the "cost of an entirely new comparable facility" using a third method based upon detailed power plant cost information compiled by the United States Department of Energy ("DOE"). The information he relied upon is found in Section 3 and Appendix E of a DOE Report entitled "Market-Based Advanced Coal Power Systems" ("DOE Report").[17] T.T., Sept. 13, 2010, at 122:20-25, 124:1-7; PTX 144. Section 3 of the DOE Report contains over thirty pages describing the physical and mechanical characteristics of a "model" subcritical plant in detail. PTX 144 at 3.1-1 through 3.1-34 (Section 3.1). The cost entries for this plant are finely divided and well described, eliminating the need to further apportion costs. T.T., Sept. 13, 2010, at 124:8-14; PTX 144 at App. E.

At trial, the Court raised the issue of whether it would be appropriate for a "comparable" facility to reflect upgraded materials. T.T., Sept. 13, 2010, at 135:22-136:1. For the reasons in

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[17] Allegheny has objected to the admission of PTX 144. Plaintiffs have asserted in response that it is admissible as a government document. Moreover, even if not admissible, Dr. Sahu may rely on it as a document of the sort of reference typically relied upon by experts.

Argument section II.D.2.a and that Dr. Sahu gave at trial, T.T., Sept. 13, 2010, at 136:2-137:22, that would generally not be appropriate. However, the cost estimates in the DOE report reflect "state-of-the-art technology." PTX 144 at 3.3-1. Accordingly, Dr. Sahu's DOE-based cost calculations reflect the use of upgraded materials, and thus are conservative in that they are likely to overestimate the cost of a "*comparable* entirely new facility."

All of this information allowed Dr. Sahu to make informed judgments about which costs to include in the "affected facility." T.T., Sept. 13, 2010, at 123: 3-13. He adjusted the plant size in a manner consistent with Allegheny's expert, and translated costs to 1994 and 1995 using Handy-Whitman. T.T., Sept. 13, 2010, at 125:11-19; PTX 129.

The cost of the Reconstruction Projects exceeded 50 percent of the cost of the "entirely new comparable facility" based on the DOE Report for both units: Unit 1: 58 percent; and Unit 2: 59 percent. T.T., Sept. 13, 2010, at 125: 11-19; PTX 129. Thus, using the DOE Report to estimate the cost of a "comparable entirely new facility" also shows that the Reconstruction Projects exceeded the NSPS reconstruction threshold.

4. Allegheny's 1993 Evaluation of Whether the Reconstruction Projects Exceeded the 50 Percent Threshold Did Not Apply the Correct Legal Standard

Allegheny's 1993 attempt to evaluate whether the Armstrong Reconstruction Projects constituted reconstruction under NSPS was so flawed and unreliable that its author no longer stands behind it. After Allegheny decided to proceed with the projects, Allegheny senior executive Clark Colby directed Jeff Mooney, a young engineer, to assess whether the projects would subject Armstrong to NSPS and other Clean Air Act requirements. T.T., Sept. 23, 2010, at 209:2–9. Mr. Mooney had worked as an engineer at the Armstrong station, and had not worked in Allegheny's environmental section. T.T., Sept. 23, 2010, at 209:16–210:10.

Mr. Mooney memorialized his analysis in a two page July 1993 memorandum. PTX 256. In his NSPS reconstruction analysis, he used the total cost of all work at Armstrong as the Reconstruction Formula numerator. D.T. (Jeff Mooney), Aug. 22, 2007, at 138:17–139:11; PTX 256 at AE_ARM00132855. For the denominator, he obtained an estimate of cost of a new 360 MW *power plant* – the boiler plus everything else needed to generate electricity. D.T. (Jeff Mooney), Aug. 22, 2007, at 139:12–140:23; T.T., Sept. 13, 2010, at 87:11-88:2; PTX 256 at AE_ARM00132855. Using these figures he concluded that the "Armstrong projects will cost 26% of a new facility, which is well below the NSPS limit of 50%." PTX 256 at AE_ARM00132855.

This analysis is fatally flawed. Mr. Mooney's "cost of an entirely new comparable facility" is incorrect, because it represents the cost of an *entire power plant*, not the "affected facility," *i.e.*, boiler, as required by NSPS. PTX 137 at 2-3, 15 (Attachment C) (Rasnic memorandum identifying the limited set of boiler components that make up the "affected facility."); T.T., Sept. 13, 2010, at 87:11-23. Therefore, Mr. Mooney included much more equipment than is actually in the affected facility, making the cost of the purported comparable facility much higher than it should have been. T.T., Sept. 13, 2010, at 87:11-23.[18] There is no evidence that Mr. Mooney ever consulted with anyone from Allegheny's environmental compliance staff about this NSPS analysis.

Since authoring the memorandum Mr. Mooney acknowledged that his reconstruction analysis is incorrect. At his 2007 deposition, he learned, for the first time, that "facility" for

[18] Mr. Mooney's memorandum contains other flaws, too. He provided no information on the bases and assumption underlying either the numerator or denominator. It does not show, for example, whether the cost estimate was for a "comparable" unit. T.T., Sept. 13, 2010, at 88:3-6; PTX 256 at AE_ARM00132855. Mr. Mooney also erred by failing to analyze the unit 1 and unit 2 Reconstruction Projects separately. T.T., Sept. 13, 2010, at 87:11-18.

NSPS purposes refers to the boiler, not the entire power plant. D.T. (Jeff Mooney), Aug. 22, 2007, at 177:15-178:9. Mr. Mooney acknowledged that had he known this in 1993 he would have determined the cost of "an entirely new comparable facility" differently, and in keeping with the NSPS definitions. D.T. (Jeff Mooney), Aug. 22, 2007, at 178:11–179:21.

Mr. Mooney also observed that "the [Allegheny] environmental department really should have been the ones making that [reconstruction] call." D.T. (Jeff Mooney), Aug. 22, 2007, at 151:20-24. In short, to the extent that Allegheny attempted to evaluate whether the Reconstruction Projects would trigger NSPS emissions control requirements, Allegheny relied on a legally defective analysis performed by an inexperienced junior employee.

5. The Infeasibility of Meeting NSPS Emissions Standards Has Not Been Demonstrated

a. NSPS Presumes That the Emissions Standards Are Technologically and Economically Feasible

The second part of the NSPS reconstruction definition requires that it be technically and economically feasible to meet the NSPS standards. 40 C.F.R. § 60.15(b)(2) [PTX 2219 (d)]. As a matter of law, however, technological and economic feasibility is presumed for all facilities within an NSPS category. Thus, the owner or operator of the facility, here Allegheny, bears the burden of showing infeasibility.

EPA presumes that compliance with NSPS emission limits is technologically and economically feasible unless the facility owner demonstrates otherwise. *See* PTX 2212 (d) at 2 (EPA December 1992 applicability determination finding reconstruction when the 50 percent threshold had been crossed and EPA was "not aware of any technological or economic limitations which would make Upjohn incapable of complying with the applicable NSPS"); PTX 2213 (d) at 2 (EPA June 1999 applicability determination finding reconstruction without

any discussion of feasibility); PTX 2214 (d) at 4 (EPA December 1981 applicability determination stating that section 60.15(b) "grant[s] [EPA] discretion to exempt sources in individual cases . . . where NSPS compliance is not 'technologically or economically feasible'"). The regulations directly embody this presumption, as they place the burden on the facility owner to identify any technological or economic limitations on compliance with the NSPS emissions limits. 40 C.F.R. § 60.15(d)(7) [PTX 2219 (d)] (requiring the owner to submit information setting forth "any economic or technical limitations" in complying with the emissions standards after the replacement.")

EPA presumes technological and economic feasibility because EPA evaluates those issues when it initially promulgates the NSPS standards for the category. Section 111(a) of the Clean Air Act expressly requires EPA to determine that systems to achieve the emission reductions have been "adequately demonstrated," and to take into account various factors including the "cost of achieving such [emission] reduction." 42 U.S.C. § 7411(a). Thus, when EPA promulgated the NSPS for electric utility steam generating units in 1979, it had concluded that the emissions limitations it selected were technically and economically feasible. *See* 44 Fed. Reg. 33580 (June 11, 1979) [PTX 2160 (d)]. In particular, EPA found that the reducing SO_2 to the NSPS standard "can be achieved *at the individual plant level* even under the most demanding conditions" through use of flue gas desulfurization ("FGD") systems, also known as "scrubbers," together with currently practiced coal preparation techniques. 44 Fed. Reg. at 33582 (2d column) [PTX 2160 (d)] (emphasis added); *see also id.* at 33592-595 (further discussion of technologies assessed and their feasibility). Thus, the feasibility of using scrubbers for SO_2 control is presumed for the Armstrong boilers.

b. The Record Shows That Compliance with NSPS Emissions Limits is Feasible at Armstrong

Even if plaintiffs bore the burden of proving feasibility, the record in this case shows that meeting the NSPS emissions limits is feasible at Armstrong 1 and 2.

i. Technological Feasibility Is Established on This Record

Expert testimony and documentary evidence show that meeting the NSPS requirements is technologically feasible at Armstrong 1 and 2. Dr. Sahu was accepted as an expert in air pollution control. T.T., Sept.13, 2010, at 42:12-25. He has experience with sulfur dioxide control in general and has observed scrubbers, specified scrubber designs, and keeps up with scrubber technological developments. T.T., Sept. 13, 2010, at 93:7-24. He explained that installing scrubbers or using low sulfur coal were available SO_2 control options in the mid-1990s. T.T., Sept. 13, 2010, at 93:19-24. Based upon his experience and knowledge, and his examination of the Armstrong plant, he testified that there were no technological barriers to installing scrubbers at Armstrong 1 and 2. T.T., Sept. 13, 2010, at 94:3-9.

In addition, two separate engineering reports produced at Allegheny's direction, one in 1991 and one in 2001, found technologically feasible scrubber options for Armstrong 1 and 2. PTX 119 at AE_HQ_00286863 (finding three FGD technologies passed screening analysis for all Allegheny plants except Rivesville), PTX 125 at AE_HQ_00268945 -946 (recommending that Allegheny consider several FGD technologies, all of which could be installed within the plant site).[19] These reports even proposed conceptual layouts for scrubber installations. T.T., Sept. 13, 2010, at 94:23-97:10; PTX 119 at AE_HQ_00287201 - 203; PTX 125 at

[19] Though Allegheny chose and retained the engineering consultant and directed it to undertake the 2001 study on its behalf, Allegheny has objected to the admission of PTX 125 as hearsay. Plaintiffs assert in response to Allegheny's objections that this study has a high degree of reliability and, therefore, is properly admissible into evidence. *See* Docket Item 459 at 2-4.

AE_HQ_00269109 - 113. Because Allegheny offered no contrary evidence, technological feasibility has been amply demonstrated.

ii. Economic Feasibility Is Established On This Record

Those same two engineering reports show that installing scrubbers on Armstrong 1 and 2 is economically feasible. EPA has used as a threshold cost of $3,000 per ton of SO_2 removed for determining economic feasibility for boilers under NSPS. *See e.g.* PTX 2159 (d) at 3 (October 20, 1994 applicability determination). Allegheny's own studies show scrubbers can be installed at Armstrong for far less.

A few years after the Reconstruction Projects, Allegheny directed the Washington Group, an engineering company with which it had an existing professional association, to "perform a technical and economic evaluation of available Flue Gas Desulfurization (FGD) processes for potential application to Allegheny's coal-fired generating stations." PTX 125 at 6 ("FGD Report"). The FGD Report concluded that for Armstrong 1 and 2, three technologies that meet or exceed the NSPS requirements existed, with a cost of control ranging between $700 to $760 per ton of SO_2 removed. PTX 125 at AE_HQ_00268943 (Table S-2).

In February 1990, before the Reconstruction Projects, Allegheny had directed United Engineers & Constructors, Inc. to perform a similar study. PTX 119 at AE_HQ_00286812. That study found that several technologically viable FGD (scrubber) options existed for Armstrong 1 and 2 with a minimum cost of $1,423 per ton of SO_2 removed. PTX 119 at AE_HQ_00286816 (Table 1.0-1, magnesium enhanced lime process). Thus, the costs in both studies was far below EPA's benchmark infeasibility threshold of $3,000 per ton of SO_2 removed.

iii. Allegheny's Successful Operation of Mitchell 3 for 30 Years with a Scrubber Shows the Feasibility of Scrubbers at Armstrong.

Finally, Allegheny's installation and successful operation of a scrubber at a plant similar to Armstrong 1 and 2 also demonstrates technological and economic feasibility. In 1980, Allegheny installed a scrubber on Mitchell 3. DTX 1052 at 8-1. Mitchell 3 and Armstrong 1 and 2 have many similarities. All are subcritical boilers, and were placed in service in the same time frame (Mitchell in 1963, Armstrong in 1958 and 1959), although Mitchell 3 has a somewhat larger capacity than either Armstrong unit (approximately 288 MW vs. 176 MW). DTX 1052 at 2-1, 4-1, 8-1.

For some 30 years the Mitchell 3 scrubber has functioned well and reduced SO_2 concentrations to 0.1-0.12 lb./million BTU. T.T., Sept. 13, 2010, at 94:15-20. This experience supports the conclusion that it is technologically feasible to meet the NSPS emissions limits of 1.2 lb./million BTU at the Armstrong 1 and 2 boilers.

Economic feasibility is demonstrated by Mitchell 3's successful operation from 1980 to today. In the early 2000s, Allegheny directed Sargent & Lundy, a well known engineering firm, to conduct an extensive study of the performance of all of its plants. DTX 1052 at 1-1; T.T., Sept. 22, 2010, at 203:2-9, T.T., Sept. 23, 2010, at 73:19-74:8. The Mitchell plant's non-fuel production costs, which include scrubber costs, compare favorably with the group of "peer" plants selected by Sargent & Lundy. DTX 1052 at AE_HQ_00269727. Mitchell 3's many years of successful operation with a scrubber while reporting better than average non-fuel production costs shows that operating scrubbers at the Armstrong units would be economically feasible.

Furthermore, thirty years ago this Court rejected arguments similar to those Allegheny is making in the case at bar. The Mitchell scrubber was installed as a result of litigation between

Allegheny and federal and state agencies. *United States v. West Penn Power Co.*, 460 F. Supp. 1305 (W.D. Pa. 1978). In that litigation, Allegheny argued that installing scrubbers was technologically, logistically and economically infeasible, and postulated that Mitchell 3 would be shut down for economic reasons if a scrubber were required. 460 F. Supp. at 1311-12. This Court found that installing and operating a scrubber was technologically, logistically and economically feasible, and that Allegheny would not shut down the boiler. 460 F. Supp. at 1308, 1310-12. Experience since 1980 shows that this Court was correct. Mitchell 3 generates electricity to this day, while reducing SO_2 emissions with a scrubber. The experience at Mitchell 3 further shows that meeting NSPS requirements at Armstrong 1 and 2 is technologically and economically feasible.

E. <u>Allegheny's Defenses and Counterarguments to the NSPS Claims Fail</u>

1. Allegheny's Challenges to Plaintiffs' Estimates of the Costs of "Comparable Entirely New Facility" Lack Merit

a. Allegheny's Challenges to Plaintiffs' Original Costs and Escalated Original Costs Analyses Fail

Plaintiffs anticipate that Allegheny will object on two grounds to plaintiffs' demonstration that the Armstrong Reconstruction Projects exceeded the NSPS 50 percent reconstruction threshold based on original costs and escalated original costs: (1) the EPA guidance advising the use of original cost basis is not applicable to reconstruction, and (2) plaintiffs' "comparable" facility is wrong because the "comparable entirely new facility" does not reflect a contemporary power plant. Neither of these objections has merit.

First, Allegheny will likely assert that EPA's letter to the Wisconsin Electric Power Company, DTX 134 (d), addressed only *modification* under NSPS, not *reconstruction*, so that it is inapplicable. T.T., Sept. 13, 2010, at 164:2-8 (counsel's questions about the letter). This

objection does not honor the text of the letter and ignores the larger context of the NSPS program. In the letter, EPA states that it is appropriate to use the original basis, rather than updated costs "in determining NSPS applicability." DTX 134 (d) at 4. This statement is not limited to modification. *Id.*; *see also* T.T., Sept. 13, 2010, at 168:18–169:13. EPA found that using original basis was consistent with Congress' intent in creating the NSPS program to foster the replacement of old dirty facilities with newer less polluting facilities. DTX 134 (d) at 5.

Moreover, even if EPA's determination only addressed modification, relying on its teaching for reconstruction would be appropriate. A regulatory provision's context should be considered when construing its meaning. *SBC Inc. v. F.C.C.*, 414 F.3d 486, 506 (3d Cir. 2005).[20] The context of the NSPS "reconstruction" and "modification" definitions show that they should be interpreted consistently. NSPS modification and reconstruction were promulgated in the same package of regulations, *see* 40 Fed. Reg. 58415 (Dec. 16, 1975) [PTX 2201 (d)], and follow each other in the regulations. 40 C.F.R. § 60.14 (modification); 40 C.F.R. § 60.15 [PTX 2219 (d)] (reconstruction). As the preamble to this rulemaking shows, these "reconstruction" and "modification" have the same purpose: establishing procedures for applying the "best adequately demonstrated control technology to existing facilities to which some changes have been made." 40 Fed. Reg. at 58417 (3d column) [PTX 2201 (d)]. Reconstruction and modification also share the overarching purpose of NSPS: replacing old "dirty" facilities with newer less polluting ones. It follows that capital costs should be interpreted consistently for NSPS "modification" and "reconstruction."

[20] Rules of statutory interpretation also apply to regulations. *Burns v. Barnhart*, 312 F.3d 113, 125 (3d Cir. 2002).

Allegheny's second criticism relates to both the original cost and escalated original cost approaches. Allegheny's expert, Mr. Golden, asserts that an approach that relies upon the boilers' original design – whether costs are escalated from original basis or not – is not appropriate because "the best that analysis could do would be to potentially keep track of raw materials, labor efficiencies; things of that nature . . . . It would not capture things such as advances in design, changes in codes." T.T., Sept. 28, 2010, at 97:22-98:1.

Plaintiffs generally agree that the original cost based approaches do not account for "advances in design, changes in codes." However, plaintiffs disagree that this means their approach is flawed. To the contrary, a "comparable" facility should mirror the size and design of the original as closely as possible. The "comparable" facility should not be a boiler that would be built from scratch at the time of the component replacements, and should not include design advances. As Dr. Sahu explained, including design changes and code changes into the "entirely new" facility, would improperly read "comparable" out of the regulatory definition. T.T., Sept. 13, 2010, at 136:19-23, 137:24–138:9.

b. Allegheny's Challenges to Plaintiffs' Analysis Based on the DOE Report Fail

Plaintiffs also expect Allegheny to challenge plaintiffs' reconstruction analysis based on the DOE Report. Mr. Golden alleged that DOE's cost projections were too low at the time of this report. T.T., Sept. 28, 2010, at 97:6-11. DOE projected power plant construction costs at $1,000 - $1,200/kW, when Mr. Golden believes that $2,000/kW was a more realistic value. T.T., Sept. 28, 2010, at 97:6-15. Mr. Golden identified no support for his higher figure. In fact, his testimony on this point was contradicted by Clark Colby, Allegheny's Rule 30(b)(6) corporate designee witness on the Armstrong Reconstruction Projects, who testified that at the time of the Armstrong projects he knew that "the generally accepted cost for building a new

coal-fired plant with all of the latest emission control technologies was between $1,000 and $1,200 a kilowatt." D.T. (Clark Colby), June 22, 2007, at 185:16-19.

Mr. Golden also opined that it would be better to use actual cost information than DOE's projected costs. T.T., Sept. 28, 2010, at 97:1-5. Plaintiffs agree that actual cost information is best, and that the "cost of a comparable entirely new facility" is best represented using the actual Armstrong cost information that plaintiffs used in their first two approaches, discussed above. *See* T.T., Sept. 13, 2010, at 129:3-20. Nevertheless, Section 3 and Appendix E of the DOE Report can be used to make an acceptable estimate of the cost of "an entirely new comparable facility." T.T., Sept. 13, 2010 at 123:3-13.

2. Allegheny's NSPS Reconstruction Analyses Are Flawed and Should Be Rejected

At trial, Allegheny presented the reconstruction analysis of its expert, Mr. Golden. His estimate of the cost of an "entirely new comparable facility" is flawed, however, and should be rejected by this Court.

a. Mr. Golden's Use of the Technical Assistance Guide Was Improper

Mr. Golden's analysis of the cost of a "comparable entirely new facility" is invalid because he has misused the industry guide upon which he bases the analysis. Mr. Golden based his estimate of the cost of a "comparable entirely new facility," the denominator of the Reconstruction Formula, on a document published by the Electric Power Research Institute (EPRI), a utility industry research organization ("EPRI"). T.T., Sept. 28, 2010, at 83:24–84:7; PTX 145 at AE_DUN_00168918 (EPRI report). The document, entitled the "Technical Assistance Guide" ("TAG" or "Guide"), contains "information for use in preliminary resource

planning in the electric utility industry." PTX 145 at AE_DUN_00168502. TAG, however, contains several limitations on its use that Mr. Golden either overlooked or ignored.

Perhaps Mr. Golden's most significant error is ignoring limitations on the use of TAG cost data. The Guide's very first section states:

> **TAG™ cases do not have the depth in design and cost estimate details required by the site-specific cases and, hence, *the comparison between a site-specific case and a TAG™ case is not appropriate*.**

PTX 145 at AE_DUN_00168541 (italics added, bold in original); *see also* T.T., Sept. 13, 2010, at 126:10-25. A similar limitation warning appears at the beginning of TAG's Section 8. It states that the estimates provided in that section:

> are *idealized for representative generating units* and have been normalized where possible to produce a consistent database for most recently completed EPRI planning studies. The estimates are *not intended* to apply to *specific utilities at specific sites*, since site conditions and utility-specific conditions dictate design and cost variations.

PTX 145 at AE_DUN_00168629 (emphasis added).

Mr. Golden did exactly what the TAG authors said should not be done: he compared cost estimates derived from a TAG case, Example 1.1A, with site-specific actual cost data for the Reconstruction Projects. T.T., Sept. 28, 2010, at 92:23-94:3. Mr. Golden did not offer any justification for ignoring EPRI's express limitations on the use of TAG estimates.

In addition, the TAG authors expect users to understand the underlying data, judgments, and assumptions before using TAG cost information:

> **TAG data incorporate adjustments made in cost studies, which reflect staff judgments to include demonstration and commercial data. These are the most recent data available on these technologies. The user is advised to review the references cited to obtain more detailed information**.

PTX 145 at 8-19 (bold in original). Another warning also admonishes the user "**not to retrieve cost and performance data from TAG™ exhibits without also reviewing the assumptions made in developing the data**." PTX 145 at 1-2 (bold in original).

There is no evidence that Mr. Golden made any effort to review the references used to develop the TAG cost information, or to consider the assumptions, adjustments and judgments that went into the Guide's estimated costs. The cost estimates he generated from TAG contrary to the report's numerous express warnings are not reliable.

*b. Mr. Golden's Reconstruction Analysis is Invalid Because It Is Based upon Unsupported Assumption*s

Because TAG lacks detailed information, Mr. Golden had to make many unsupported assumptions that render his estimate of the cost of an "entirely new comparable facility" invalid. As the case law holds, unsupported assumptions cannot provide the foundation for proper expert testimony. *See Stecyk v. Bell Helicopter Textron, Inc.*, 295 F.3d 408, 414 (3d Cir. 2002). In addition, Dr. Sahu explained that the best approach to determining "an entirely new comparable facility" is the one that requires the fewest assumptions. T.T., Sept. 13, 2010, at 129:3-9. Because of the limitations of the TAG report, however, Mr. Golden had to make two broad categories of unsupported assumptions: unsupported assumptions regarding comparability and regarding apportionment of costs. T.T., Sept. 13, 2010, at 101:6-22.

i. Unsupported Assumption of Comparability

First, the Guide does not provide enough information to know how similar or dissimilar the hypothetical unit Mr. Golden used is to the Armstrong boilers. T.T., Sept. 13, 2010, at 103:6-9; PTX 145 at 8-26. Mr. Golden used TAG's 300 MW subcritical boiler model unit as his surrogate facility. T.T., Sept. 28, 2010, at 140:1-3; PTX 145 at AE_DUN_00168654 (example 1.1A). The TAG model plant examples contain only skeletal information about

hypothetical plants, such as nominal rating, forced outage rate, and whether it is baseloaded. T.T., Sept. 28, 2010, at 140:1-3; PTX 145 at AE_DUN_00168654. Virtually no information on the boiler components, boiler design or location is provided. Costs are provided for broad categories that are poorly described and are not related to the affected facility. *See* PTX 145 at AE_DUN_00168648 - 663.

The data underlying TAG entries, which could be studied to determine if the generic, hypothetical plant could represent a "comparable entirely new facility" to the Armstrong boilers, is not available for review. No background data is provided in the body of TAG, nor is it available otherwise. Though he tried, Dr. Sahu could not obtain access to the references and data used by EPRI. T.T., Sept. 13, 2010, at 102:18–103:5, 142:2-4.

Because of the paucity of information on the hypothetical plant and costs in TAG, it is impossible to know if the TAG hypothetical example used by Mr. Golden is "comparable" to the Armstrong boilers or not. As Dr. Sahu explained "I can only guess. It's really not possible to make a judgment based on the level of detail provided." T.T., Sept. 13, 2010, at 103:7-9. [21]

There is no evidence that Mr. Golden considered whether the TAG hypothetical plant represents a "comparable entirely new facility" to the Armstrong boilers. He did not explain what he considered to be an "entirely new comparable facility" to the Armstrong boilers, or why the TAG example could reliably estimate costs of an "entirely new comparable facility." T.T., Sept. 28, 2010, at 83:21-84:7. He offered no explanation for why he did not use – or even refer to – the existing Armstrong boilers, which are comparable to themselves. *See* T.T., Sept. 13, 2010, at 101:23–102:7. Mr. Golden did not testify that he examined the underlying data to

[21] The paltry amount of information about the hypothetical plants and their costs in TAG contrasts sharply with the extensive amount of detailed plant and cost information in the portions of the DOE Report Dr. Sahu used. *See* Argument Section II.D.3.a., above.

determine if the model he used, Example 1.1A, is “comparable” to the Armstrong boilers. Accordingly, the record is devoid of evidence demonstrating that Allegheny’s TAG based cost estimate reflects costs for a “comparable entirely new facility” relative to the Armstrong boilers.

ii. Unsupported Apportionment of Costs

Mr. Golden’s apportionment of costs between the “affected facility” and the rest of the plant is not reliable because it is also based on unsupported assumptions. TAG provides cost estimates for broad categories of a power plant, such as Steam Generator, Turbine Generator and so forth. *See* PTX 145 at AE_DUN_00168654. These categories are not based on the “affected facility.” T.T., Sept. 13, 2010, at 101:12-17. To use these costs in a reconstruction analysis it is necessary to make judgments about what portion of the costs in the category are “in” the affected facility and which are not. T.T, Sept. 13, 2010, at 108:2-9. TAG, however, does not provide enough information to do this apportionment. In the absence of the needed information, Mr. Golden made unsupported assumptions.

Mr. Golden concluded that the TAG Steam Generator category costs were wholly “in” the affected facility, that the Turbine Generator, Coal Handling and Environmental categories were totally “out,” and that Balance of Plant, General Facilities and Engineering and Project and Process Contingency categories were partially “in” the affected facility. DTX 1762. However, General Facilities and Engineering and Balance of Plant are not defined in the TAG glossary. PTX 145 at AE_DUN_00168530 - 535. Though most of the categories are *described* in TAG Section 8, the descriptions are inadequate to make apportionments. T.T., Sept. 13, 2010, at 109:7-112:11 (noting that the Steam Generator, General Facilities and Engineering, and Project and Process Contingency categories have inadequate descriptions and the Balance of Plant category has no description); PTX 145 at AE_DUN_00168645 – 646, AE_DUN_00168651.

Moreover, to the extent the report describes the General Facilities category, it lists "roads," an item that is without question not in the affected facility. T.T., Sept. 13, 2010, at 111:11-112:3.

Apparently, Mr. Golden recognized that the dearth of information about the items categories and their costs would prevent any reasoned apportionment. He manufactured an apportionment method using a ratio of the capital costs of the Steam Generator item, which he assumed is totally "in" the affected facility, and the capital costs of the three categories he assumed were totally "out" of the affected facility. T.T., Sept. 13, 2010, at 112:12-20. He multiplied the other capital cost categories by this ratio. *Id.* The record lacks any explanation about why a ratio of costs of certain categories relates to whether the items in other categories are "in" or "out" of the affected facility. Mr. Golden just states that he used this ratio, providing no explanation, justification or support. T.T., Sept. 28, 2010, at 89:19–90:9. The flaws in this arbitrary apportionment are obvious: as Dr. Sahu observed, "one does not know the error one is making in that approach." T.T., Sept. 13, 2010, at 112:21-24. Given the number of unsupported assumptions in Mr. Golden's testimony, the Court should give that testimony no weight.

iii. Mr. Golden's Reconstruction Analysis is Invalid Because It Does Not Honor All of the Words of the Regulation.

Finally, Mr. Golden's analysis is invalid because it does not address all of the words of the reconstruction regulation, 40 C.F.R. § 60.15(b)(1) [PTX 2219 (d)]. It is well established that when interpreting and applying regulations, meaning should be a given to every word. *Idahoan Fresh v. Advantage Produce, Inc.*, 157 F.3d 197, 202 (3d Cir. 1998). Mr. Golden violates that canon of construction because he ignores a key word in the regulation: "comparable." He does not explain how the TAG hypothetical unit that he relied upon is "comparable" to the Armstrong boilers, other than stating that he chose a hypothetical plant with the size closest to the Armstrong units. T.T, Sept. 28, 2010, at 85:4-6. Without doing so, his analysis is invalid.

iv. Application of Mr. Golden's Cost Figures Shows Their Implausibility

Using the EPRI data and calculations described above, Mr. Golden determined that the cost of building a "comparable entirely new" Armstrong 1 boiler in 1995 would be $672/kW, and the cost of building a "comparable entirely new" Armstrong 2 boiler in 1994 would be $659/kW. T.T., Sept. 28, 2010, at 92:3-6; DTX 1762. The Armstrong units are approximately 176 MW each. Multiplying Mr. Golden's cost figures with the units' size in MW gives the cost of constructing a "comparable entirely new" unit 1 as $118,272,000, and the cost of constructing a "comparable entirely new" unit 2 as $115,984,000. These figures are outside the realm of any reasonable assumptions as to the cost of constructing a comparable entirely new facility, since in replacing *virtually all* of the boiler components, Allegheny spent *less than half* of those amounts: $52,421,805 for unit 1, and $53,302,358 for unit 2.

3. Allegheny Has Failed To Demonstrate Infeasibility

Plaintiffs also anticipate that Allegheny will claim that installing scrubbers is not feasible. However, Allegheny has failed to carry its burden on this issue.

a. Technological Feasibility

Allegheny offered no expert or lay testimony that meeting NSPS emissions standards is technologically infeasible at the Armstrong boilers. Thus, Allegheny has failed to carry its burden to rebut the technological feasibility presumption.

b. Economic Feasibility

The evidence that Allegheny offered failed to show economic infeasibility under the NSPS standards. Allegheny's purported economic infeasibility evidence was brief, non-expert testimony from Peter Skrgic, a retired company executive. T.T., Sept. 22, 2010, at 169:18–171:1. He testified that Allegheny obtained an estimate for a common scrubber to control both

Armstrong units' emissions. T.T., Sept. 22, 2010, at 170:6-7. However, he said that the company was philosophically opposed to using a common scrubber. T.T., Sept, 22, 2010, at 170:7-16. Mr. Skrgic said that the cost of installing individual scrubbers at each Armstrong unit would have been "out of the ballpark" and therefore not economically feasible. T.T., Sept. 22, 2010, at 170:18–171:1. Mr. Skrgic identified no support for this conclusory testimony.

The NSPS reconstruction regulation contemplates that an operator seeking to rebut the presumption of feasibility would provide "a discussion of any economic or technical limitations the facility may have in complying with applicable standards of performance after the proposed replacements." 40 C.F.R. § 60.15(d)(7) [PTX 2219 (d)]. Even had Mr. Skrgic's testimony been communicated to the PA DEP at the time of the projects, it does not meet this threshold. First, his testimony was not relevant to the "applicable standards of performance," namely NSPS emissions standards. It instead related to another program, the 1990 Title IV acid rain provisions of the Clean Air Act ("Acid Rain Program"), and in particular related to Allegheny's deliberations about the most economical way to comply with the requirements of that program. T.T., Sept. 22, 2010, at 169:18-24, 176:12–177:3, 178:5-8. The Acid Rain Program, however, is separate and independent from NSPS and controls pollutants on a system-wide basis, so that a utility has a choice as to which generating units, if any, to install pollution controls on. *See* Background and Facts section II.D above. NSPS, on the other hand, applies to individual generating units. Background and Facts section II.B above. The Clean Air Act specifically states that compliance with the Acid Rain Program has no effect on compliance with other provisions of the Clean Air Act, including NSPS. 42 U.S.C. § 4651b(f) (Title IV statute). Thus, Mr. Skrgic's testimony about whether it made sense for Allegheny to comply with its system-

wide Title IV obligations by installing scrubbers on some of its power plants is irrelevant to whether installing scrubbers was infeasible under the facility-specify NSPS regulations.

Regardless, Allegheny's evidence on infeasibility is not credible. Mr. Skrgic's testimony on "infeasibility" consists only of broad statements devoid of analysis or other support. If Allegheny had really developed a cost estimate for separate scrubbers at Armstrong, as Mr. Skrgic suggested, T.T., Sept. 22, 2010, at 170:11-18, there would have been a record of it in the approximately 1.5 million pages of documents Allegheny produced.

Furthermore, even if the testimony is assumed to be credible, it does not show infeasibility. The NSPS feasibility test that EPA applies is whether the cost of pollutant removal exceeds approximately $3,000 per ton. PTX 2159 (d) at 3 (October 1994 applicability determination). In the mid-1990s, EPA determined that costs of less than $3,000 per ton of pollutant removed were feasible. PTX 2159 (d) at 3 (EPA October 1994 applicability determination). No Allegheny witness provided evidence that the cost of installing scrubbers at Armstrong would exceed that amount. In fact, in the early 1990s Allegheny estimated the cost of installing scrubbers at Armstrong at approximately half that amount, $1,423 per ton of SO_2 removed. PTX 119 at AE_HQ_00286816. Instead, Mr. Skrgic stated that Allegheny was opposed to a common scrubber for philosophical reasons because malfunction of a common scrubber would shut down both units. T.T., Sept, 22, 2010, at 170:8-16. However, the record is devoid of any evidence about how likely it was that this scenario would occur, if it did occur how long it would last and to what extent it would affect the Armstrong plant's operations and profitability, or measures that Allegheny could have taken to mitigate these postulated problems.

A bald assertion of a concern does not constitute infeasibility. Allegheny's preference to not do something for "philosophical" or other reasons does not excuse it from NSPS emission

limitations. *See West Penn*, 460 F. Supp. at 1315-16 (in non-NSPS litigation Allegheny's objection to installing a scrubber because it would not be available 100 percent of the time did not make the scrubber infeasible). At best, Mr. Skrgic's testimony shows that Allegheny did not want to install scrubbers at Armstrong. However, not wanting to comply is not infeasibility.

III. ALLEGHENY IS LIABLE FOR VIOLATING PENNSYLVANIA'S NEW SOURCE PERMITTING REQUIREMENTS (CLAIM NOS. 6 AND 12)

A. Summary of Argument

Allegheny's reconstruction of the Armstrong 1 and 2 boilers without prior approval of PA DEP violated Pennsylvania law. Pennsylvania regulations define reconstructed emission units as "new sources." Pennsylvania uses the same 50 percent reconstruction threshold as the NSPS reconstruction definition, but Pennsylvania has no feasibility element. Thus, the same compelling evidence which showed that the Armstrong Reconstruction Projects exceeded the NSPS 50 percent threshold also shows that the reconstructed Armstrong boilers are new sources under Pennsylvania's regulations.

Under Pennsylvania law, owners or operators must seek and obtain a permit, known as a "plan approval," before commencing work on a "new source" and must reduce emissions to the extent possible by using the "best available technology" ("BAT"). Because Allegheny reconstructed the Armstrong boilers without meeting either of those requirements, it is liable for violations of the Pennsylvania new source regulations.

B. The Legal Standard

In Claim Nos. 6 and 12 ("PA Reconstruction Claims"), plaintiffs assert that Allegheny's total rehabilitation of Armstrong 1 and 2 boilers made them "new sources" under Pennsylvania regulations, and therefore triggered the requirements to obtain approval from the state and use BAT to control air contaminant emissions, among other things. These claims are similar to the

NSPS reconstruction claims and share one principal element with them: the 50 percent test. However, the PA Reconstruction Claims have an independent legal basis and implicate a different remedy than the NSPS Claims.

Under Pennsylvania law, reconstructed emission units are defined as "new sources":

> *New source* —A stationary air contamination source which:
>
> . . . .
>
> (ii) Was modified, irrespective of a change in the amount or kind of air contaminants emitted, so that the fixed capital cost of new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new source; fixed capital costs means the capital needed to provide the depreciable components.

25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "new source"). Thus, section (ii) of the Pennsylvania's new source definition is nearly identical to the NSPS 50 percent reconstruction test, 40 C.F.R. § 60.15 (b)(1). Pennsylvania's definition, however, has no feasibility component.

If a reconstructed emission unit or "source" meets the requirements of subsection (ii) the owner or operator of must obtain approval from the PA DEP before commencing construction or modification. 35 P.S. § 4006.1(a); 25 Pa. Code § 127.11 [PTX 2209 (d)]. This pre-construction permit is called a "plan approval." T.T., Sept. 14, 2010, at 91:10-13.

Pennsylvania regulations specify the requirements that must be demonstrated in an application for plan approval. 25 Pa. Code § 127.12(a) [PTX 2209 (d)]. The applicant must show and DEP must find, among other things, that emissions will be the "minimum attainable through the use of the best available technology." 25 Pa. Code §§ 127.12(a)(5) [PTX 2209 (d)].

Pennsylvania regulations define BAT as:

> *Best available technology* — Equipment, devices, methods or techniques as determined by the Department which will prevent,

> reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available.

25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of best available technology). BAT is determined when the application is submitted. 25 Pa. Code § 127.12(a)(5) [PTX 2209 (d)].

Thus, the elements of liability on plaintiffs' BAT claims are: (1) there must be a stationary air contamination source, (2) that source was modified so that the fixed capital cost of new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new source; and (3) Allegheny did not obtain a plan approval or operate the plant in compliance with BAT emissions standards.

C. The Evidence Demonstrates that Allegheny Violated Pennsylvania New Source Permitting Requirements by Reconstructing the Armstrong Boilers <u>Without Complying With Plan Approval Requirements</u>

The elements of the PA Reconstruction Claims are either admitted by Allegheny or established by the evidence presented that proves the NSPS violations. There is no dispute that the Armstrong units qualify as stationary air contamination sources, given their emission of thousands of tons of pollutants each year. PTX 63. The analysis to satisfy the 50 percent "reconstruction" test under the Pennsylvania new source definition is identical to the NSPS Reconstruction Formula analysis. As discussed in detail in the preceding sections, plaintiffs have shown that the Armstrong Reconstruction Projects exceeded the 50 percent reconstruction threshold by a wide margin. *See* Argument sections II.D.1 & 2 above.

Allegheny has admitted that it did not submit a plan approval application or obtain a plan approval for the Reconstruction Projects. PTX 2 ¶¶ 189, 252. Allegheny has also admitted that it has not installed BAT to reduce emissions at the Armstrong boilers. PTX 2 ¶¶ 190, 253. Accordingly, plaintiffs have established all elements of the PA Reconstruction Claims.

D. Allegheny's Defenses and Counterarguments to the PA Reconstruction Claims Fail

To the extent that Allegheny challenges the evidence plaintiffs have presented to demonstrate that the costs of the Reconstruction Projects exceeded the 50 percent threshold, plaintiffs have already shown why those challenges fail. *See* Argument section II.E above.

Plaintiffs anticipate that Allegheny will argue that plaintiffs' evidence is irrelevant because Pennsylvania's regulations look at the cost of a comparable "source" while the federal NSPS regulations look at the cost of a comparable "facility." This semantic argument is meritless. Both the federal NSPS regulations and the Pennsylvania regulations use the terms "source" and "facility," but the meanings are reversed: a "facility" under NSPS is a "source" under Pennsylvania's program and vice versa.

Under the NSPS regulations "affected facility" is defined as follows:

> *Affected facility* means, with reference to a stationary source, any apparatus to which a standard is applicable.

40 C.F.R. § 60.2 [PTX 2218 (d)]. In the preamble to the NSPS reconstruction provisions, EPA explained the difference between source and facility: "[g]enerally speaking, 'sources' are entire plants, while facilities are identifiable pieces of process equipment or individual components which when taken together would comprise a source." 40 Fed. Reg. 58415, 58416 (Dec. 16, 1975) (1st column) [PTX 2201 (d)].

However, the Pennsylvania regulations define "facility" differently:

> *Facility* – An air contamination source or a *combination of air contamination sources* located on one or more contiguous or adjacent properties and which is owned or operated by the same person under common control.

25 Pa. Code § 121.1 [PTX 2208 (d)] (emphasis added). Thus, under Pennsylvania law the "facility" is the larger thing, a collection of emission units, but "source" is treated as the smaller

thing, the individual emission unit. Pennsylvania practice, policies, and administrative and appellate case law show that Pennsylvania defines "source" and "facility" in this manner.

For example, PA DEP issues Title V operating permits for the entire plant or "facility," but requirements are included in the permit for the individual emission units, which are called "sources." *See, e.g.*, 25 Pa. Code § 127.502(a) [PTX 2209 (d)] (Title V permit regulation referring to "stationary air contamination sources in the Title V facility"); PTX 1209 at AE_HQ_00593575 (Title V permit referring to the "Facility"); *id*. at AE_HQ_00593578 (Title V permit listing each "source" at the Armstrong plant). Allegheny itself identified the Armstrong 1 and 2 boilers as separate "sources" in its Title V application for the plant. PTX 1210 at AE_HQ_00136681.

A PA DEP guidance policy evinces the Department's use of these definitions in the specific context of the Pennsylvania 50 percent test, indicating that *one* glass furnace is a source within a larger *glass plant*:

> Should the fixed capital cost of the new components exceed 50% of the fixed capital cost that would be required to construct a *comparable new source* the glass furnace will be considered as a *new source per Section 121 [of the Pennsylvania regulations] and will also be subject to NSPS requirements*.

PTX 2206 (d) at Sect. 4.3 (PA DEP Technical Guidance Document No. 275-2101-004) (emphasis added).

Finally, decisions of the Pennsylvania appellate courts and the Pennsylvania Environmental Hearing Board ("EHB")[22] show that under Pennsylvania air pollution law a "source" is a smaller entity within a "facility." *See, e.g.*, *Sunoco, Inc. v. PA DEP*, 865 A.2d 960,

[22] The Environmental Hearing Board is the administrative tribunal with jurisdiction to hear appeals from PA DEP actions. 35 P.S. §§ 7511-7516.

962-963 (Pa. Cmwlth. 2005) (referring to an entire refinery as a "facility" and to individual boilers at the refinery as "sources"); *Sunoco, Inc. v. PA DEP*, 2004 E.H.B. 191, 195-96 [PTX 2203 (d)] (EHB decision referring to an entire refinery as a "Facility," and to each of the industrial boilers as a "source"); *Groce v. PA DEP*, 921 A.2d 567, 570 (Pa. Cmwlth. 2007) (referring to entire power plant as a "facility");.*Groce v. PA DEP*, 2006 E.H.B. 856, 858, 867 [PTX 2204 (d)] (EHB decision referring to the proposed power plant as a "facility" and to individual combustion units as "sources"); *Belitskus v. PA DEP*, 1998 E.H.B. 846, 855-56 [PTX 2205 (d)] (EHB decision referring to furnace, lime kiln and two boilers as "sources").

The foregoing shows that PA DEP and EPA use the same words to mean different things but accomplish the same goal. Under either set of regulations, if an owner or operator replaces boiler components to a degree that the 50 percent reconstruction threshold is exceeded, the emission unit will be subject to additional air pollution control requirements.

IV. ALLEGHENY IS LIABLE FOR VIOLATING THE FEDERAL AND PENNSYLVANIA PREVENTION OF SIGNIFICANT DETERIORATION REQUIREMENTS (CLAIM NOS. 1-2, 7-8, 15-20 AND 23-24)

A. Summary of Argument

There are two principal disputes on plaintiffs' PSD claims: whether the PSD Projects should have been expected to increase emissions, and whether the PSD Projects were "routine maintenance, repair and replacement" ("RMRR") work that was exempt from PSD requirements. The Court should find in plaintiffs' favor on those issues and the other elements of those claims.

Emissions. Plaintiffs have met their burden on emissions. Under EPA's regulations, PSD permitting and pollution reduction requirements become applicable to a generating unit if a project performed at the unit is expected to cause the unit to increase emissions by 40 tons per year or more after the unit resumes operation. Plaintiffs have proven that Allegheny should have

expected the PSD Projects to increase the amount of time that the Armstrong, Hatfield's Ferry and Mitchell 3 units operated and thus increase the amount of pollution emitted by those units

First, Allegheny's own documents establish that it should have expected the PSD Projects to result in an emissions increase. Allegheny itself expected that the PSD Projects would increase availability of each generating unit by dozens if not hundreds of hours each year. Given that these units are large enough to generate 40 tons of pollution in just a few hours, it would only have required that Allegheny use the units for only a small percentage of those additional available hours to cross the 40-ton threshold. In fact, however, Allegheny's practice was to use these units a large percentage of the time they were available -- well over 50 percent. So Allegheny should have expected to increase the units' hours of operation by dozens if not hundreds of hours, more than enough to generate 40 tons of additional pollution.

Second, plaintiffs have offered expert opinion testimony from Robert Koppe and Dr. Richard Rosen confirming that a reasonable projection consistent with the PSD regulations would have shown projected emissions increases of greater than 40 tons per year. Using Mr. Koppe's determinations and Allegheny's data, Dr. Rosen performed the calculations required by the PSD regulations to determine whether the expected increase in availability would lead to increased pollution. His calculations were consistent with the various limitations applicable to PSD emissions analyses set out in EPA regulations and guidance. He concluded, in most cases, that the PSD Projects should have been expected to increase emissions by more than 40 tons. Plaintiffs have dropped their claims where his calculations did not show a 40-ton increase.

Allegheny's principal argument against Dr. Rosen's results – that his PSD calculations are unreliable because his projections do not match the actual post-project emissions levels – is at first blush appealing, but is in fact legally wrong. The PSD emissions regulations constrain

the information that may be used in performing PSD emissions projections to exclude the effect of factors independent of the project at issue, except in certain narrow circumstances not present here. Just as taxable income is a legal construct that differs from one's everyday understanding of income due to a variety of deductions, exemptions, carry-overs and so forth, PSD emission projections are a legal construct that may differ from the actual post-project emissions due to various regulatory constraints. Because of those constraints, and because of the inherent, unpredictable variability of future events, PSD projections may not match the actual outcome, and thus whether or not Dr. Rosen's projections did match the actual outcomes does not show that his conclusions are unreliable. The evidence at trial demonstrated that his calculations adhered to the constraints of the PSD regulations and considered the relevant information available before the projects, making his projections as reliable as PSD projections can be.

RMRR. Allegheny has not met its burden on the RMRR defense. The RMRR defense is limited to *de minimis* activities. The PSD Projects were not *de minimis* activities, however. They were large capital projects costing hundreds of thousands to millions of dollars that are performed rarely – only once or twice – during a generating unit's lifetime. They involved months if not years of planning, lengthy outages, the replacement of large boiler components weighing tens of thousands to hundreds of thousands of pounds, the hiring of multiple outside contractors to fabricate and install the equipment, and the installation of special cranes or monorails to move the equipment. The majority of courts have held, including on summary judgment, that such projects are not RMRR.

Allegheny's RMRR arguments fail because they are based on expert testimony that does not recognize the *de minimis* nature of the RMRR exemption and is inconsistent with the majority rule in the courts and EPA guidance. Allegheny asks the Court to look at a small subset

of the largest, most expensive, most extensive replacement projects performed at power plants, and then conclude that because the PSD Projects in this case were just as large, expensive and extensive, they are "routine." Thus, by restricting the set of projects considered, Allegheny biases the result: Allegheny's approach is no more rational than saying that a human height of 6'7" is "routine" because that is the average height of an NBA player.[23] When one compares the large, expensive PSD Projects with the overall universe of tens of millions of maintenance, repair and replacement projects that have occurred at power plants over the past decades, the PSD Projects are not routine

B. <u>The Legal Standard</u>

1. The Statutory Background

In enacting the PSD provisions of the Clean Air Act in 1977, Congress' purpose was to protect public health and welfare and to assure that economic growth could occur without worsening air quality. 42 U.S.C. § 7470(1), (2) & (3). In addition, Congress intended the PSD program to ensure that emissions from sources in one state will not interfere with efforts to prevent significant deterioration of air quality in another state. 42 U.S.C. § 7470(4). To achieve these goals, Congress directed that any decision to allow increased air pollution be made only after careful evaluation of all consequences of such a decision, including the interstate effects. 42 U.S.C. § 7470(5).

In enacting the PSD statute, Congress anticipated that "old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants." *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir.

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[23] Although not material to this case, the average height of NBA players is in fact about 6'7". *See, e.g.*, NBA, 2007-08 Player Survey: Height, *at* http://www.nba.com/news/survey_height_2007.html

2006), *cert. denied*, 549 U.S. 1338 (2007). To ensure that utilities did not "string out the life" of older plants to avoid the need to build new plants with stringent pollution controls, Congress directed that the utilities install pollution controls if existing plants were modified. *New York v. EPA*, 413 F.3d 3, 45 (D.C. Cir. 2005) (Williams, J., concurring); *see also Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) (hereinafter, "*WEPCO*") ("Congress did not permanently exempt existing plants from [PSD] requirements"); *Alabama Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979) ("The statutory scheme intends to 'grandfather' existing industries; but the provisions concerning modifications indicate that this is not to constitute a perpetual immunity from all standards under the PSD program."); *United States v. Southern Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1009-10 (S.D. Ind. 2003) (hereinafter, "*SIGECO*") ("the [Clean Air Act] should not be interpreted in a way that 'would open vistas of indefinite immunity from the provisions of NSPS and PSD'") (quoting *WEPCO*, 893 F.2d at 909).

Congress created the PSD preconstruction permitting program in order to prevent increases in pollution in areas with acceptable air quality from deteriorating. *See, e.g.* 42 U.S.C. § 7475 (captioned "Preconstruction requirements" and requiring that no "construction" occur at a major emitting facility before issuance of a PSD permit); *see also* 42 U.S.C. § 7479(2)(B). Under the statute, preconstruction permits are required if a utility planned to undertake "construction," which Congress defined to include "modification." 42 U.S.C. § 7479(2)(C).

Congress defined "modification" very broadly: "*any physical change* in, or change in the method of operation of, a stationary source *which increases the amount of any air pollutant emitted by such source* or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4) (emphasis added). Thus, Congress created no exemptions:

any physical change which would produce *any* increase in emissions was subject to the PSD preconstruction permitting requirements.

2. The PSD Regulations

EPA promulgated regulations implementing the PSD statute in 1980, 45 Fed. Reg. 52676 (Aug. 7, 1980), and revised those regulations in 1992, 57 Fed. Reg. 32314 (July 21, 1992) [PTX 2217 (d)]. Although those EPA regulations use the term "major modification" rather than the statutory term "modification," the regulations, like the statute, define the term "major modification" broadly: a major modification includes "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase" of a regulated pollutant. 40 C.F.R. § 52.21(b)(2)(i) [PTX 2210 (d)].

Accordingly, plaintiffs must prove four elements to establish liability on their PSD claims at the Armstrong, Hatfield's Ferry and Mitchell plants: (1) the plant is a "major stationary source"; (2) the project at issue is a "physical change" at that source; (3) the project would have been expected to result in "a significant net emissions increase" of the regulated pollutants SO_2 or NO_x; and (4) Allegheny did not obtain a PSD permit or operate the plant in compliance with BACT emissions standards. Because the Clean Air Act is a strict liability statute, *see, e.g., United States v. Anthony Dell'Aquilla, Enter.*, 150 F.3d 329, 332 (3rd Cir. 1998), plaintiffs do not have to prove any element relating to Allegheny's state of mind or intent.

Because Pennsylvania adopted the federal PSD regulation by reference, 25 Pa. Code §§ 127.81, 127.83 [PTX 2209 (d)], the elements that PA DEP must prove for its Pennsylvania-law PSD claims (claims 2, 8, 16, 18, 20 and 24), as well as the governing substantive law for those claims, are the same as for the plaintiffs' federal PSD claims (claims 1, 7, 15, 17, 19 and

23). Plaintiffs bear the burden of proof on the elements of their PSD claims. Docket Item 220 at 21, *adopted with unrelated changes by* Docket Item 380; *see also SIGECO*, 245 F. Supp. at 998.

C. The Evidence Demonstrates that Allegheny Violated the PSD Regulations

Plaintiffs' evidence establishes each element of liability on plaintiffs' PSD claims.

1. The Armstrong, Hatfield's Ferry and Mitchell 3 Power Stations Are Major Stationary Sources

Under the PSD regulations, the term "major stationary source" includes, among other things, any fossil-fuel fired steam electric plant of more than 250 million Btu/hr that emits or has the potential to emit 100 tons per year or more of any air pollutant subject to regulation under the Clean Air Act. 40 C.F.R. § 52.21(b)(1)(i) [PTX 2210 (d)]. Plaintiffs have met their burden on this first element because the parties have stipulated that the Armstrong, Hatfield's Ferry and Mitchell power stations are major stationary sources under the federal and Pennsylvania PSD regulations. Docket Item 430 at 1, ¶ 5.

2. The PSD Projects Were Physical Changes

Neither the statute nor the regulations provide a definition of "any physical change." For decades, however, the federal courts of appeals have consistently given the term the broadest definition possible: "any" physical change means exactly that – *any* physical change. *See, e.g., New York v. EPA*, 443 F.3d 880, 890 (D.C. Cir. 2006) ("Congress's use of the word 'any' in defining a 'modification' means that all types of 'physical changes' are covered")[24]; *WEPCO*, 893 F.2d at 908 (the plain language of the statute, the legislative history and decisions of other courts support the conclusion that "'any physical change' means precisely that"); *Alabama*

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[24] Decisions of the D.C. Circuit are particularly authoritative in interpreting the Clean Air Act, as Congress gave that court exclusive jurisdiction to perform judicial review of national Clean Air Act regulations. 42 U.S.C. § 7607(b)(1).

Power Co. v. Costle 636 F.2d 323, 400 (D.C. Cir. 1979); *see also SIGECO*, 245 F. Supp. 2d at 1009.

Thus, "any physical change" includes replacement of existing components with identical or functionally equivalent components, known as "like-kind" replacements. *WEPCO*, 893 F.2d at 907-910. In particular, courts have found that the replacement of secondary superheater outlet headers, parts of reheaters, parts of economizers and parts of the lower slope panels are "physical changes." *United States v. Cinergy Corp.*, 495 F. Supp. 2d 909, 937-39, 943-48 (S.D. Ind. 2007) (parts of reheaters, lower slopes and primary superheaters); *Ohio Edison*, 276 F. Supp. 2d at 840-842, 844-845 (secondary superheater outlet headers, parts of lower slopes, parts of economizer); *id.* at 854.

The two PSD Projects at the two Armstrong units consisted of replacing and upgrading multiple major components, including the superheater, reheater, economizer, air heaters, ductwork and sootblowers. PTX 1318 at R-3 09513; PTX 206 at R-3 09953. The five PSD Projects at the Hatfield's Ferry power station consisted of replacing and upgrading major components, including a pendant reheater and crossover tubes at one unit, a pair of secondary superheater outlet headers at one unit, and the entire set of lower slope panels and seal skirts at all three units. *See*, *e.g.*, Docket Item 430 ¶ 42, PTX 747 at AE_HQ_017985; Docket Item 430 ¶ 35, PTX 213 at R-3 02949; Docket Item 430 ¶¶ 28, 50, 58, PTX 704 at AE_DUN_0005218. The PSD Project at the Mitchell 3 unit consisted of replacing and upgrading 24 front and rear lower slope panels. Docket Item 430 ¶ 68; PTX 890 at R-3 06898. Under the authority set out above, these PSD Projects are all "physical changes."

3. Allegheny Should Have Expected the PSD Projects to Produce Significant Net Emissions Increases of SO_2 and NO_x

Plaintiffs' evidence also establishes the third element on liability for plaintiffs PSD claims: Allegheny should have projected, before construction began, that the PSD Projects would result in significant net emissions increases of SO_2 and NO_x. Consistent with all other courts to have ruled on the issue, this Court held that the legal standard for the PSD claims is "whether a reasonable projection, pursuant to the actual to projected actual test, would have predicted a [significant] net increase in emissions." Transcript of Pretrial Conference (Aug. 27, 2010), at 6:1-4; *see also United States v. Cinergy Corp.*, 384 F. Supp. 2d 1272, 1276 (S.D. Ind. 2005), *aff'd*, 458 F.3d 705 (7th Cir. 2006), *cert. denied*, 549 U.S. 1338 (2007); *Ohio Edison*, 276 F. Supp. 2d at 865-66; *United States v. Southern Indiana Gas & Elec. Co*, No. IP99-1692-C-M/F, 2002 WL 1629817, at *3 (S.D. Ind. July 18, 2002).

a. The Regulations and Guidance Governing PSD Emissions Calculations

The regulations set out a two-stage process for calculating a "net emissions increase" under the actual-to-projected actual test. 40 C.F.R. § 52.21(b)(3)(i) [PTX 2210 (d)]. The first stage is to calculate the anticipated emissions increase *from the project*. 40 C.F.R. § 52.21(b)(3)(i)(*a*) [PTX 2210 (d)]; *see also* PTX 2211 (d) at 7 (1987 EPA applicability determination stating that "[t]he first step is to determine whether the particular physical or operational change in question *would itself* result in a significant increase in actual emissions.") (emphasis added). The second stage, known as "netting," consists of adjusting the result of the first stage by adding or subtracting certain other increases or decreases *from other activities* at the same source. 40 C.F.R. § 52.21(b)(3)(i)(*b*) [PTX 2210 (d)]. An emissions increase is

"significant" if it exceeds specific threshold amounts: 40 tons per year for SO_2 and NO_x. 40 C.F.R. § 52.21(b)(23)(i) [PTX 2210 (d)].

The regulations provide the following additional requirements for the two-stage PSD emissions calculation.

i. Stage 1: The Anticipated Change in Emissions from the Project

In stage 1, one computes the difference between (a) annual "actual emissions" during a two-year pre-project "baseline" period and (b) anticipated annual "actual emissions" for a two-year period after the project to determine if the project is expected to cause an emissions increase. *See* 40 C.F.R. §§ 52.21(b)(3)(i)(*a*), (b)(21)(ii), (b)(33) [PTX 2210 (d)]. During the baseline period, the "actual emissions" for a generating unit are measured as "the average rate, in tons per year, at which the unit actually emitted the pollutant." 40 C.F.R. § 52.21(b)(21)(ii) [PTX 2210 (d)]. Those baseline emissions "shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted" during the baseline period. *Id.*

For the post-project period, the "actual emissions" for a generating unit are its "representative actual annual emissions," defined as "the average rate, in tons per year, at which the source is *projected* to emit a pollutant for the two-year period after a physical change." 40 C.F.R. § 52.21(b)(33) [PTX 2210 (d)] (emphasis added). In calculating these projected future emissions, the regulations require that one "[c]onsider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act." 40 C.F.R. § 52.21(b)(33)(i) [PTX 2210 (d)]. Further, in the preamble to its July 1992 PSD regulations, EPA specified that, to calculate the projected future emissions from a project, one

multiplies together two figures: (1) the anticipated hourly emissions rate of the unit, and (2) the projected capacity utilization of the unit. 57 Fed. Reg. 32314, 32323 (2nd column) (July 21, 1992) [PTX 2149 (d) (excerpts); PTX 2217 (d) (full version)].

PSD emissions projections are also subject to what is known as the "demand growth exclusion," pursuant to which one must exclude from a post-project emission estimate:

> that portion of the unit's [post-project emissions] following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

40 C.F.R. § 52.21(b)(33)(ii) [PTX 2210 (d)].

ii. Stage 2: Netting

The second stage of the PSD emissions analysis, "netting," determines the "net" emissions increase by adjusting any anticipated emissions increase from the first stage by "[a]ny other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable." 40 C.F.R. § 52.21(b)(3)(i)(*b*) [PTX 2210 (d)]. In this context, a "source" extends beyond the particular generating unit at which the project is being performed to include all of the generating units within a plant. *See, e.g.*, 51 Fed. Reg. 43814, 43830 (Dec. 4, 1986). To qualify for "netting," an emissions reduction from another activity at the source must be "creditable." A reduction is "creditable" if it meets four criteria: it is (1) "federally enforceable," (2) "surplus," (3) "permanent," and (4) "quantifiable." *See, e.g.*, *id.* at 43831-32.

An emissions decrease is "federally enforceable" if it has been approved by EPA and thereby incorporated into the SIP for the state in which the facility is found. *See* 40 C.F.R. § 52.21(b)(17) [PTX 2210 (d)]; 60 Fed. Reg. 2912, 2914 (Jan. 12, 1995).

An emissions decrease is "surplus" if it "is not required by current regulations in the SIP . . . and not used by the source to meet any other regulatory requirement." 51 Fed. Reg. at 43832. Under this criterion, if the source has already relied on an emissions reduction to meet one federal regulatory requirement, it cannot be used to meet another regulatory requirement through netting, "since this would be 'double counting' of the emissions reduction." PTX 173 at 3 (EPA memorandum concluding that reductions used to meet RACT requirement could not be used in netting). Thus, to be surplus an emissions reduction must voluntarily go beyond federal requirements. In 1994, for example, EPA determined that NO_x reductions were creditable only if they were "above and beyond" any reductions required to meet "reasonably available control technology," or RACT, requirements. PTX 174 at 2.

A "permanent" emissions reduction is exactly what the plain language indicates – a reduction that will not increase in the future: "[p]ermanence may generally be assured by requiring federally enforceable changes in source permits or applicable state regulations to reflect a reduced level of allowable emissions." 51 Fed. Reg. at 43832. A "quantifiable" reduction is "quantifiable both in terms of estimating the amount of the reduction and characterizing that reduction for future use." *Id.*

iii. Synthetic minor permits

A plant operator planning a project that was expected to produce a significant net emissions increase and therefore constitute a "major modification" can avoid PSD or other new source review ("NSR") requirements by obtaining a "synthetic minor" permit in which it agrees to limit the plant's emissions. Under the CAA, construction projects that are not anticipated to generate enough emissions to constitute a "major modification," are known as "minor." *See, e.g.*, 60 Fed. Reg. 39907, 39907 (Aug. 4, 1995). If the plant operator agrees to limit the

emissions of a contemplated source or project to less than "major" levels, the source or project is referred to as a "synthetic minor," because the source or project only becomes minor by virtue of the enforceable operational restrictions. *See id.*; *see also* 59 Fed. Reg. 44460, 44463 (Aug. 29, 1994) ("minor NSR permits have become the vehicle of choice for creating 'synthetic minor new sources' and 'synthetic minor modifications'").

Thus, for example, a utility could agree to a synthetic minor permit containing enforceable restrictions on the number of hours a generating unit is used or the sulfur content of the fuel burned at the unit to avoid projecting a significant net emissions increase that would trigger PSD requirements. By obtaining the synthetic minor permit, the utility would be making the emissions reduction federally enforceable and otherwise qualified for netting.

b. Allegheny Was on Notice That It Should Have Expected the PSD Projects to Produce Significant Net Emissions Increases

Ample evidence shows that Allegheny should have expected each of the PSD Projects to cause significant net emissions increases. First, Allegheny easily could have determined before it undertook the projects that the projects would increase availability by more than a trivial amount and that as a result usage of the units and emissions would increase by more than 40 tons.

Allegheny understood the connection between increases in availability and increases in generation. Allegheny expected the PSD Projects to increase unit availability by eliminating forced outages. As a 1998 or 1999 Allegheny memorandum stated: "[i]ncreased unit availability due to in-kind material replacement is assumed with any project." PTX 184 at AE_DUN_00131831. Then, in every Allegheny economic analysis justifying a component replacement, the major financial benefit was the fact that there would be no cost for replacement power because the unit would become more available and therefore generate more electricity –

the electricity that Allegheny previously had to purchase elsewhere during the forced outages the old component had been causing. T.T. Sept. 20, 2010 at 19:16-21:23. As just one example, in analyzing the Hatfield's Ferry lower slope projects, Allegheny assumed that the project would eliminate 768 hours of outages each year at the three Hatfield units and as a result cause generation at those units to increase by 302,630,400 kilowatthours PTX 704 at AE_DUN_00005228 (multiplying 8 outages by 4 days by 24 hours to get 768 hours; dividing $28,516,863 value of replacement energy by $0.09423 assumed value of each replacement kilowatthour to get 302,630,400 kilowatthours). Allegheny's expert Jerry Golden agreed that Allegheny expected the PSD Projects to increase unit availability and that those expected increases were key: "the economic justification was all centered on improved reliability and availability of the units." T.T., Sept. 28, 2010, at 41:20-22.

Across the spectrum, Allegheny's documents confirm that Allegheny expected the projects to increase availability and/or generation:

Project	Purpose of Project	Expected Availability Increase for the PSD Project, Based on Allegheny's Documents	Expected Generation Increase, Based on Allegheny's Documents
Armstrong 1: Radiant Side and Convection Side[25]	To remedy "increased unavailability rate"	201 hours/year	Not calculated
Armstrong 2: Radiant Side and Convection Side[26]	"[T]o improve the overall reliability and availability of the boiler"	201 hours/year	Not calculated
Hatfield 1: Lower Slope[27]	Project "will improve the availability and reliability of the boiler"	256 hours/year	100,876,800 kilowatthour ("kwh")/year
Hatfield 1: Secondary Superheater Outlet Headers[28]	To improve the availability and reliability" of Hatfield Unit 1	72 hours/year	Not calculated

[25] The source for the purpose of the project in this row is PTX 204 at R-3 09562. As for the availability increase, the source of the information is Mr. Mooney's emissions calculations, PTX 178 at AE_ARM00132601. Multiplying Mr. Mooney's 4.6 percent anticipated availability increase by 8,760 hours in year, produces an expected availability gain of 403 hours/year. Mr. Mooney's analysis, however, did not distinguish between the work in plaintiffs' PSD Projects, and the work that Allegheny allocated to the low-NO_x burner work order. Accordingly, as a rough, "ballpark" approximation, plaintiffs have allocated only one-half of the total availability increase, 201 hours, to the PSD Project.

[26] The source for the purpose of the project in this row is PTX 850 at 1. Plaintiffs calculated the availability figure as described in the preceding footnote.

[27] The source for the purpose of the project in this row is PTX 216. As for the availability and generation figures in this row, Allegheny calculated the increased availability and generation for the three lower slope projects at the three Hatfield's Ferry units together. PTX 633 at R-3 02096 (calculating availability gain as "8 OUT/YR X 4 DAY/YR [*sic*] x 24 HR/DAY"); *id.* (calculating generation increases as "8 OUT/YR X 4 DAY/YR [*sic*] x 24 HR/DAY x .710 x 555 MW x 1000KW/MW"). For the purpose of this chart, plaintiffs have divided those aggregate figures by three to calculate the average availability and generation increases expected for each individual project.

[28] PTX 723 at AE_HQ_00369760. The expected increase in availability is based on PTX 565 at AE_DUN_00412488. In that economic analysis, Allegheny "conservatively estimated" that each Hatfield unit would experience one forced outage of 72 hours per year. The estimate is based on the fact that unit 1 experienced 3 forced outages related to the SSOH over a 3 year period.

Project	Purpose of Project	Expected Availability Increase for the PSD Project, Based on Allegheny's Documents	Expected Generation Increase, Based on Allegheny's Documents
Hatfield 2: Pendant Reheater[29]	To "optimize the future availability and reliability of the boiler" "A new reheater will definitely improve the station's availability"	72 hours/year	29,690,280 kwh/year
Hatfield 2: Lower Slope[30]	Project "will improve the availability and reliability of the boiler"	256 hours/year	100,876,800 kwh/year
Hatfield 3: Lower Slope[31]	Project "will improve the availability and reliability of the boiler"	256 hours/year	100,876,800 kwh/year
Mitchell 3: Lower Slope[32]	Project "is necessary to improve plant availability"	182 hours/year	Not calculated

[29] The source for the purpose of the project in this row is PTX 747 at AE_HQ_017985 and PTX 211 at AE_DUN_00674620. As for the expected increase in availability and generation, plaintiffs based those figures on Allegheny's economic analysis for the project, PTX 715. In that analysis, Allegheny calculated the increased availability and generation it expected from the project. PTX 715 at AE_DUN_00194044 (calculating availability gain as "3 Outages/Year x 3 Days/Outage x 24 Hours/Day"); *id.* (calculating generation increases as "3 Outages/Year x 3 Days/Outage x 24 Hours/Day" x .743 x 555 MW x 1000 KW/MW = 89,070,040 KWhr/Yr"). In performing those calculations, Allegheny assumed that the reheater project would eliminate (1) one outage per year that had been occurring already in the past, and (2) two outages per year that were not yet occurring but would occur in the future if Allegheny did not undertake the project. PTX 715 at AE_DUN_00194043 (discussion in first paragraph on the page) Accordingly, since only one third of the expected future benefit related to improving availability relative to past experience, plaintiffs have only included one-third of the expected availability benefit, 72 hours, and one-third of the expected generation increase, approximately 29 million kilowatthours, on this chart.

[30] The source for the purpose of the project in this row is PTX 181 at AE_HQ_00567616. Plaintiffs calculated the expected increase in availability and generation as explained in footnote 27 above.

[31] The source for the purpose of the project in this row is PTX 591at AE_HQ_00285925. Plaintiffs calculated the expected increase in availability and generation as explained in footnote 27 above.

[32] The source for the purpose of the project in this row is PTX 890 at R-3 06898. The capital work order for the project indicates that the project was intended to eliminate the "3.8 leaks per year in this ash hopper area." *Id.* A conservative estimate of the length of each forced

Based on those large expected increases in availability, Allegheny was on notice that it should have expected these PSD Projects to increase emissions of SO_2 and NO_x by more than 40 tons per year. Although on first impression, 40 tons of emissions sounds like a lot, in the context of these large coal-fired generating units, it is a small amount. As a ballpark figure, Mr. Koppe estimated at trial that, at the time of these projects, the Hatfield's Ferry units would have generated 40 tons of SO_2 in about six hours. T.T., Sept. 20, 2010, at 45:6-7.

Using its own data, as just a back-of-the-envelope evaluation, Allegheny could easily have calculated the hourly emissions rate for SO_2 and NO_x for each of the relevant generating units in the year before the project to see just how few hours of additional generation would result in emissions increases that cross the 40-ton thresholds. For example, each year, Allegheny reported to PA DEP the annual emissions amounts for each of the generating units at issue in this case for the previous year. *See* PTX 1309-1 through PTX 1309-53. Simply dividing the annual emissions amount for a unit by the total number of hours in a year, 8,760, provides a conservative estimate[33] of the unit's hourly emissions rate. Then, by taking the forty-ton threshold, and dividing by the hourly emissions rate, one can determine the number of hours of increased operation were needed to cross the threshold.

Applying this simple calculation to Allegheny's own data shows the minimal number of hours of operation necessary to generate an additional 40 tons of SO_2 or NO_x. For SO_2, the

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outage for those leaks is two days. *Compare* PTX 633 at R-3 02096 (assuming that one forced outage lasted four days); PTX 715 at R-3 02096 (assuming that one forced outage lasted for three days). At two days, or 48 hours, for each of the 3.8 outages expected, on average, the expected availability gain would be 3.8 x 48 = 182.4 hours

[33] This hourly emissions rate calculation would be conservative because it assumes that the unit ran every hour during the year at 100 percent output level. Since in reality no coal-fired generating unit runs every hour during a year at 100 percent output level, the actual hourly emissions rate would be higher.

results of those calculations are as follows (plaintiffs have omitted the Mitchell 3 project from this chart because they no longer have a SO_2 PSD claim for that project):

Project	Annual Emissions (Year Preceding Project)	Hourly Emissions Rate	Number of Hours Needed to Emit 40 Tons	Number of Hours of Increased Availability Based on Allegheny's Documents
Armstrong 1: Radiant Side and Convection Side[34]	19,155 (1994)	2.19	18.3 hours	201 hours
Armstrong 2: Radiant Side and Convection Side[35]	16,366 (1993)	1.87	21.4 hours	201 hours
Hatfield 1:[36] Lower Slope	52,162 (1996)	5.96	6.7 hours	256 hours
Hatfield 1: Secondary Superheater Outlet Headers[37]	52,162 (1996)	5.96	6.7 hours	72 hours
Hatfield 2: Pendant Reheater[38]	51,485 (1992)	5.88	6.8 hours	72 hours
Hatfield 2: Lower Slope[39]	49,057 (1998)	5.60	7.1 hours	256 hours
Hatfield 3: Lower Slope[40]	49,911 (1995)	5.70	7.0 hours	256 hours

The calculations for NO_x emissions are as follows:

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[34] The source for the annual emissions amount for this project is PTX 1309-3.

[35] The source for the annual emissions amount for this project is PTX 1309-2.

[36] The source for the annual emissions amount for this project is PTX 1309-22.

[37] The source for the annual emissions amount for this project is PTX 1309-22.

[38] The source for the annual emissions amount for this project is PTX 1309-18. Because the emissions from Hatfield's Ferry 2 are split between two emissions stacks at the plant, Allegheny reports two lines of data for that unit, and the total emissions from the plant are the sum of those two lines of data.

[39] The source for the annual emissions amount for this project is PTX 1309-24. Because the emissions from Hatfield's Ferry 2 are split between two emissions stacks at the plant, Allegheny reports two lines of data for that unit, and the total emissions from the plant are the sum of those two lines of data.

[40] The source for the annual emissions amount for this project is PTX 1309-21.

Project	Annual Emissions (year preceding project)	Hourly Emissions Rate (tons/hour)	Hours of Operation Needed to Emit 40 Tons	Expected Hours of Increased Availability Based on Allegheny's Documents
Armstrong 1: Radiant Side and Convection Side[41]	6,346 (1994)	0.724	55.2 hours	201 hours
Armstrong 2: Radiant Side and Convection Side[42]	4,644 (1993)	0.530	75.4 hours	201 hours
Hatfield 1:[43] Lower Slope	8,597 (1996)	0.981	40.8 hours	256 hours
Hatfield 1: Secondary Superheater Outlet Headers[44]	8,597 (1996)	0.981	40.8 hours	No expected increase in Allegheny documents
Hatfield 2: Pendant Reheater[45]	12,159 (1992)	1.39	28.8 hours	72 hours
Hatfield 2: Lower Slope[46]	7,021 (1998)	0.801	49.9 hours	256 hours
Hatfield 3: Lower Slope[47]	7,823 (1995)	0.893	44.8 hours	256 hours
Mitchell 3: Lower Slope[48]	5,964 (1994)	0.681	58.8 hours	182 hours

As the chart illustrates, to generate a 40 ton increase in SO_2 emissions from the Hatfield's Ferry 2 lower slope project, Allegheny would only have had to expect to use the unit 7.1 hours,

[41] The source for the annual emissions amount for this project is PTX 1309-3.
[42] The source for the annual emissions amount for this project is PTX 1309-2.
[43] The source for the annual emissions amount for this project is PTX 1309-22.
[44] The source for the annual emissions amount for this project is PTX 1309-22.
[45] The source for the annual emissions amount for this project is PTX 1309-18. Because the emissions from Hatfield's Ferry 2 are split between two emissions stacks at the plant, Allegheny reports two lines of data for that unit, and the total emissions from the plant are the sum of those two lines of data.
[46] The source for the annual emissions amount for this project is PTX 1309-24. Because the emissions from Hatfield's Ferry 2 are split between two emissions stacks at the plant, Allegheny reports two lines of data for that unit, and the total emissions from the plant are the sum of those two lines of data.
[47] The source for the annual emissions amount for this project is PTX 1309-21.
[48] The source for the annual emissions amount for this project is PTX 1309-37.

or less than three percent, of the 256 hours of expected availability increase. For none of the projects would Allegheny have had to use a unit for more than half of the additional available time to generate 40 tons of SO_2 or NO_x.

In the 1990s, however, Allegheny actually used its Armstrong, Hatfield's Ferry and Mitchell 3 units most of the time they were available. For example, the Hatfield's Ferry units were not used 3 percent of the time they were available, but about 75-85 percent of the time they were available. *See, e.g.*, PTX 1991, PTX 1993, & PTX 1997 (stating utilization factors). For Armstrong, the figure was even higher: Allegheny used those units around *90* percent of the time they were available. *See* PTX 1969 & PTX 1977 (stating utilization factors). Allegheny used the Mitchell 3 unit about 69 percent of the time it was available. PTX 2009.

In sum, before implementing the projects, if Allegheny had done simple back-of-the-envelope calculations to compare (a) how few additional hours of generation it would have taken to produce 40 tons of emissions with (b) how many additional hours it expected the availability of the units to increase, it would have reasonably expected to produce significant net emissions increases under the PSD regulations. Only in the essentially unforeseeable event that Allegheny expected its patterns of usage to drastically reverse – so that units it had been using 70 to 90 percent of the time when available would instead be used less than 50 percent of the time when available – should Allegheny have *not* expected these PSD Projects to produce emissions increases of 40 tons or more. Allegheny, however, produced no evidence at trial suggesting that it anticipated any such drastic shift in usage before any of the PSD Projects. Accordingly, based on this simple type of analysis, Allegheny should have anticipated that increases in availability from the PSD Projects would result in increases in emissions greater than 40 tons per year.

c. Dr. Rosen's Calculations Confirm that Allegheny Should Have Expected the PSD Projects to Increase Emissions by More than 40 Tons per Year

Dr. Rosen concluded that Allegheny should have expected each of the PSD Projects to produce significant net emissions increases of SO_2 and NO_x. His specific estimates of the PSD emissions increases were:

Project	**SO_2**	**NO_x (High NO_x)**	**NO_x (Low NO_x)**
Armstrong 1: Radiant Side and Convection Side	798	231	98
Armstrong 2: Radiant Side and Convection Side	755	274	124
Hatfield 1: Lower Slope	964	382	143
Hatfield 1: Secondary Superheater Outlet Headers	455	180	68
Hatfield 2: Pendant Reheater	224	82	33
Hatfield 2: Lower Slope	404	158	64
Hatfield 3: Lower Slope	1,338	495	220
Mitchell 3: Lower Slope	11	57	37

PTX 2129. Thus, based on these calculations, for each of the Armstrong and Hatfield's Ferry PSD Projects, Allegheny should have projected a significant net emissions increase of 40 tons or more of SO_2.[49] Similarly, for all of the PSD Projects, Allegheny should have projected a significant net emissions increase of 40 tons or more of NO_x.

The emissions calculations that Dr. Rosen performed to reach those opinions are relevant and reliable because they (1) are actual-to-projected-future-actual calculations consistent with the PSD regulations and guidance; (2) were produced using a methodology based on undisputed principles of power plant emissions science and engineering, and (3) rely on a careful application

[49] Plaintiffs have dropped their PSD claim for the Mitchell 3 PSD Project insofar as it concerned SO_2. Docket Item 245 ¶¶ 1(c).

of the methodology to the facts of this case, principally through Allegheny's own documents and the expert opinions of Mr. Koppe.

Before turning to those calculations, however, plaintiffs note that Mr. Koppe's and Dr. Rosen's credentials are highly suited for the work they performed in this case. Mr. Koppe is an engineer who was one of the principal architects of the system that Allegheny and the rest of the utility industry use to evaluate availability, the Generation Availability Data System, or GADS. T.T., Sept. 14, 2010, at 197:23-199:21. In this case, he used the same methodology for evaluating availability that he used in decades of work for utilities. T.T., Sept. 14, 2010, at 214:19-215:22.

Dr. Rosen is a Ph.D. physicist who has spent three decades analyzing utility operations and economics, including power-plant emissions. T.T., Sept. 20, 2010, at 179:17-185:15. In this case, he used the five-equation methodology for calculating emissions that other courts have recognized as reliable and in fact have endorsed in finding utilities liable for PSD violations. *See*, *e.g.*, *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 868-869, 885 (S.D. Ohio 2003) (court describing the five equations and finding that Dr. Rosen's opinions were "a reasonable and credible basis" to evaluate emissions and find liability on 11 projects). Allegheny's expert, Mr. Graves, agreed that Dr. Rosen's five-equation methodology would provide a good evaluation of emissions so long as one used proper input values. T.T., Sept. 22, 2010, at 75:11-25.

i. Dr. Rosen Followed the PSD Regulations and Guidance in Calculating Pre-Project Emissions

Dr. Rosen followed all relevant regulations and guidance when he performed his "actual-to-projected-future-actual" calculations. Under this test, one compares past pre-project

emissions to an estimate of post-project future emissions to see whether the project would be expected to increase emissions by 40 tons or more.

With regard to the pre-project emissions, Dr. Rosen started by selecting a two-year baseline period for the pre-project emissions using the average generation or "average two of five" approach. In that approach, one selects the twenty-four month period during the five years preceding the project where generation most closely matched the average generation level over the entire five year period. T.T., Sept. 21, 2010, at 12:14-22, 51:14-54:14. The Court should find Dr. Rosen's average generation approach consistent with the regulations and appropriate for several reasons.

First, the regulations require that the two-year baseline period must fall within the five years preceding the project and must be "representative of normal source operation." 40 C.F.R. § 52.21(b)(21)(ii) [PTX 2210 (d)]; 57 Fed. Reg. 32314, 32325 (1st column) [PTX 2217 (d)]; *Ohio Edison*, 276 F. Supp. 2d at 869, 881. The *Ohio Edison* court adopted Dr. Rosen's average generation approach in ruling that eleven projects violated the PSD requirements. *Ohio Edison*, 276 F. Supp. 2d at 869 ("[t]he baseline period for the remaining three activities is the consecutive 24 months within the five years preceding the activity that is representative of the average amount of power generated during the five year period").

Aside from having judicial approval, the average generation approach also meets the requirements of the PSD regulations. By definition, the "average" is *representative* since it "*represents* the general significance of a set of unequal values." Merriam-Webster's Collegiate Dictionary (10th ed. 1993) [PTX 2220 (d)] at 80 (emphasis added). Moreover, the average is fairer because it is a central statistic biased neither in favor of the utility nor against it.

After using the average generation approach to determine baseline periods for each project, Dr. Rosen then used Allegheny data and the five-equation methodology to determine the operating hours, production rates, and types of materials combusted during the baseline period for the generating unit at which the project was performed. *See* 40 C.F.R. § 52.21(b)(21)(ii) [PTX 2210 (d)] (baseline emissions "shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted" during the baseline period). Specifically, to calculate operating hours, Dr. Rosen derived the actual availability and utilization factors from Allegheny's own records and used that information, along with the number of hours in a year. T.T., Sept. 21, 2010, at 58:19-25 (availability factor), 72:6-15 (utilization factor), 50:11-17 (explaining how part of the five-equation methodology calculates capacity utilization, or hours of operation); PTX 2150 (d). To calculate the production rate, or amount of coal burned, he used unit capacity, unit heat rate and coal heat rate to calculate the amount of coal burned. T.T., Sept. 21, 2010, at 84:5-9 (unit capacity); 84:22-85:4 (heat rate); 85:5-14 (heat content); 22:19-26:19 (explaining how five-equation methodology calculates amount of coal burned). Finally, he used the material burned, bituminous coal, and other Allegheny data, including the sulfur content of the coal, along with standard EPA emissions data, to determine the relevant emissions factors. T.T., Sept. 21, 2010, at 85:22-86:15 (SO_2); 88:10-22 (NO_x).

ii. Dr. Rosen Followed the PSD Regulations and Guidance in Calculating Post-Project Emissions

Dr. Rosen calculated projected post-project emissions consistent with EPA's July 1992 guidance for such calculations. As noted in Argument section IV.C.3.a.i above, in July 1992, EPA provided a methodology for calculating projected emissions increases under the PSD regulations that consisted of multiplying together two components: (1) the anticipated hourly

emissions rate of the unit, and (2) the projected capacity utilization of the unit. 57 Fed. Reg. 32314, 32323 (July 21, 1992) [PTX 2149 (d)]. Dr. Rosen's five-equation methodology implements that two-component approach. When Dr. Rosen multiplies together the projected future values of unit capacity, heat rate, heat content and emissions factors together, he is calculating the first component: the anticipated hourly emissions rate of the unit. T.T., Sept. 21, 2010, at 50:3-10; PTX 2150 (d). Likewise, when Dr. Rosen multiplies together the remaining factors in his methodology, namely, the anticipated unit availability factor, anticipated utilization factor and the number of hours in a year, he is calculating the second component: the projected capacity utilization of the unit. T.T., Sept. 21, 2010, at 50:11-17; PTX 2150 (d). Accordingly, the five-equation methodology corresponds to EPA's methodology. *See* T.T., Sept. 21, 2010, at 50:18-21; PTX 2150 (d).

Dr. Rosen's assumptions with regard to the post-project values for each of the factors in his equations – availability factor, utilization factor, heat rate, heat content and emissions factor – are all well grounded in the regulations, Allegheny's documents and data, industry practice, and Mr. Koppe's expert analysis.

Unit Availability Factor: Availability, or more technically, the unit "equivalent availability factor," or EAF, represents the time that the unit is available to operate: that is, the time when is not shut down for repairs. T.T., Sept. 14, 2010, at 201:18-202:11; T.T., Sept. 21, 2010, at 42:19-22. Dr. Rosen correctly incorporated expected availability increases in his calculations for those projects where Mr. Koppe concluded that it would have been reasonable to expect the project to increase availability. T.T., Sept. 21, 2010, at 59:3-64:19. For one project, Mr. Koppe found no reason to expect an availability increase, and Dr. Rosen therefore assumed

no availability increase in his calculations.[50] T.T., Sept. 21, 2010, at 64:20-65:12 (explaining that Mr. Koppe had not found an availability increase for the Hatfield 2 secondary superheater outlet header project).

Mr. Koppe performed his availability analyses by applying the same methodology to Allegheny's data that he has used when performing availability analyses for utilities over the past 35 years. T.T., Sept. 14, 2010, at 195:7-196:18, 214:19-215:22; T.T., Sept. 20, 2010, at 93:11-97:18. In evaluating whether a project would be expected to cause an availability increase, he looked at two issues: (1) the effect of the PSD Project itself on the unit's availability, and (2) the effect of "everything else" on the unit's availability. *See, e.g.*, T.T., Sept. 20, 2010, at 73:2-74:13. Within that framework, he determined that (1) Allegheny should have expected the PSD Projects themselves to reduce forced outages and increase unit availability, and (2) Allegheny should have expected no reduction, and in fact a slight increase, in unit availability due to "everything else" occurring at the unit. *Id.* at 74:13-20.

With regard to the effect of the PSD Projects themselves, Allegheny's documents repeatedly state that Allegheny expected the PSD Projects to reduced forced outages and increase availability, and in many cases calculate the reduction in outage time that Allegheny expected from the projects. *See* Argument section IV.C.3.b above. There is no legitimate argument that Allegheny did not expect these projects to have a beneficial effect on unit availability.

With regard to "everything else," Mr. Koppe noted that Allegheny anticipated reducing the number of planned outages from once a year to once every year and a half, which would

[50] Based on Mr. Koppe's evaluation, plaintiffs dropped their claims regarding that project. Docket Item 245 ¶ 1(a) (stipulated withdrawal of portions of claims relating to the Hatfield's Ferry 2 secondary superheater outlet header project).

increase the availability due to "everything else." T.T., Sept. 20, 2010, at 89:15-90:22. He also noted that at the same time as the PSD Projects, Allegheny was undertaking other projects that would improve availability. T.T., Sept. 20, 2010, at 90:23-92:16. So given the combined effects of the PSD Projects themselves and these other efforts, Allegheny should have expected unit availability to increase.

Mr. Koppe's conclusions about expected increases in availability from the PSD Projects were consistent with industry's and Allegheny's general understanding that large component-replacement projects improve availability. There is no significant dispute in the power industry on that issue. For example, in 1985 EPRI released a report providing advice about how utilities should evaluate projects to determine whether they would be economically justifiable. *See* PTX 1088. In a hypothetical example analyzed in that report, EPRI assumed that a project to replace a major boiler component would increase unit availability to levels above those experienced in the preceding four years. PTX 1088 at EP001138 - 139.

One of the principal manufacturers of boilers in the United States, Babcock & Wilcox, agrees. Babcock & Wilcox built the Hatfield's Ferry boilers, DTX 1052 at AE_HQ_00269595, and for over 100 years, has produced a detailed technical handbook on steam boilers and generation entitled *Steam: Its Generation and Use*. *See* PTX 152 (hard copy provided to the Court). In the 40th edition of *Steam*, published in 1992, Babcock & Wilcox acknowledges that capital expenditures to replace major components can improve boiler availabilities. *Id.* at 46-2. A graph shows that small capital investments can produce an availability improvement of roughly five or six percent over the course of 10-15 years. *Id.* at 46-2 (Figure 2).

Mr. Koppe has spent most of his 35-year career evaluating to what extent large capital projects like these would improve unit availability. T.T., Sept. 14, 2010, at 195:7-196:18;

209:23-210:7. In the course of that work, he has not only performed such analyses for his utility clients, but he has many times seen utility personnel use the same approach to estimating availability improvements as he used here, and he has seen transcripts of utility executives testifying that such projects would improve availability. *Id.* at 214:19-215:22.

As noted above, Allegheny's historical documents show that Allegheny expected these PSD Projects would increase unit availability: "[i]ncreased unit availability due to in-kind material replacement is assumed with any project." PTX 184 at AE_DUN_00131831. That historical belief is consistent with its current beliefs. In recent years Allegheny Chief Executive Officer Paul Evanson and Allegheny Vice President Phil Goulding have repeatedly represented to investment analysts that Allegheny expected to increase unit availability through large capital projects. *See, e.g.*, PTX 1837 at 2, 8 (in 2005, Mr. Evanson predicting that overall availability at Allegheny power stations will increase from 83 percent to 91 percent over the following three years due to work done in planned outages); PTX 1839 at 8 (in 2006, Mr. Evanson noting that Allegheny is focused on improving availability to 91 percent, and explaining that work already done had reduced forced outage rate significantly); PTX 1840 at 2 (in 2006, Mr. Evanson mentioning Allegheny's "availability improvement program," and noting that each percentage point improvement in availability systemwide is worth $10-12 million); PTX 1841 at 2 (in 2006, Mr. Evanson reporting that, as a result of work done in planned outages, Allegheny has experienced better performance and is moving towards its "91% availability goal"); *id.* at 5 (in 2006, Mr. Goulding reporting that Allegheny expects availability to be one percent higher in 2007 than in 2006); PTX 1842 at 2-3 (in 2006, Mr. Evanson explaining that, as part of its availability improvement efforts, Allegheny had already obtained seven percent reductions in forced outages due to projects it had undertaken); PTX 1843 at 7 (in 2007, Mr. Evanson

explaining that in 2008, the availability of Allegheny's plants should be up to 91 percent, and that forced outage rates had already decreased from 9.4 percent to 7.2 percent in the last year).

Utilization Factor: The utilization factor of a unit is the percentage of time the unit is actually operated when it is available to operate. T.T., Sept. 21, 2010, at 42:23-43:1. Dr. Rosen correctly determined that it was appropriate to hold the utilization factor constant in the post-project period to reflect the PSD regulations' "demand growth exception." That exception requires that one exclude from PSD emissions projections:

> that portion of the unit's emissions that could have been accommodated during the representative baseline period and *is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole*.

40 C.F.R. § 52.21(b)(33)(ii) [PTX 2155 (d)] (emphasis added). Thus, in general, the projections must exclude any change in emissions "attributable" to increased utilization of the unit caused by factors "unrelated to the particular change," *i.e.*, unrelated to the PSD Project. *See United States v. Cinergy Corp.*, No. 99-cv-1693, 2005 WL 3018688, at *3 (S.D. Ind. Nov. 9, 2005) (demand growth excluded only when unrelated to the project). In particular, the projections must exclude any changes in emissions attributable to increased utilization due to increases in electricity demand for the utility's entire generating system.

The utilization factor is the only place in Dr. Rosen's five equations where such unrelated increases in utilization would occur. T.T., Sept. 21, 2010, at 75:9-19. Accordingly, by holding the utilization factor constant, Dr. Rosen excludes those unrelated changes in utilization from his calculations and thereby meets the requirements of the demand growth exclusion. *Id.* at 74:1-75:9, 76:6-24. No Allegheny witness disputed that the constant utilization factor assumption implements the demand growth exception.

Dr. Rosen also determined that it was appropriate to hold the utilization factor constant because that was consistent with industry best practices, as evidenced by the recommendations in a 1985 EPRI report. T.T., Sept. 21, 2010, at 77:7-80:20; PTX 2152 (d) at EP001104, EP001119 (demonstrative containing highlighted excerpts from the EPRI report). The EPRI report addressed how to perform economic evaluations of the effect of large capital projects like PSD Projects on generation. *See* PTX 1088; *see also* PTX 2152 (d) (highlighted excerpts from the report used during the testimony of Dr. Rosen). EPRI recommended using a constant utilization factor in such evaluations. Trial Trans, Sept. 21, 2010, at 76:25-80:20; PTX 2152 (d) at EP001104, EP001119; *see also* T.T., Sept. 21, 2010, at 68:18-20, 90:9-11 (EPRI's term "utilization" is the same as Dr. Rosen's utilization factor). In fact, the methodology that EPRI recommended is identical to the first two steps of the methodology Dr. Rosen used in this case. T.T., Sept. 21, 2010, at 91:24-92:25; PTX 2153 (d).

EPRI explained that holding the utilization factor constant was appropriate because changes in availability were independent of the utilization factor, that is, changes in the unit's availability would generally not change the utilization factor. T.T., Sept. 21, 2010, at 79:3-18, 93:1-20; PTX 2152 (d) at EP001104, EP001134. That theoretical conclusion is consistent with Allegheny's documents, which nowhere indicates that any of the PSD Projects should have been expected to reduce the utilization factor.

As EPRI did in 1985, Allegheny's own consultants, Sargent & Lundy, in 2004 recommended the use of the constant utilization factor when evaluating the effect of projects such as the PSD Projects on electric generation. DTX 1052 at AE_HQ_00269885 – AE_HQ_00269886 (recommending that Allegheny should calculate the benefits of an "improvement in unit availability" from potential forced-outage rate improvement projects by

multiplying the expected change in unit EAF, "$EAF_A – EAF_B$", by a constant utilization factor, "U", as Dr. Rosen does).

Unit Capacity: Dr. Rosen correctly held the unit capacities constant based on Mr. Koppe's conclusion that PSD Projects should not have been expected to change those capacities. T.T., Sept. 21, 2010, at 84:2-9. No witness at trial disputed that assumption.

Unit Heat Rate: Dr. Rosen correctly held the heat rates constant based on Mr. Koppe's conclusion that PSD Projects should not have been expected to change the heat rates. T.T., Sept. 21, 2010, at 84:22-85:4. As noted in Argument section IV.C.3.a.i above, the regulations limit stage one of the PSD calculation to projecting the anticipated emissions increase, if any, *from the project*. 40 C.F.R. § 52.21(b)(3)(i)(*a*) [PTX 2210 (d)] ("[a]ny increase in actual emissions from a particular physical change or change in method of operation at a stationary source"). But there is no evidence that the Armstrong PSD Projects should have been expected to improve the heat rate. The only testimony on this point came from Mr. Koppe, who concluded that any expected efficiency improvements would have been the result of other work being done on the boilers, not the PSD Projects. T.T., Sept. 20, 2010, at 110:16-23. No witness disputed that conclusion.

Nor did any witness dispute Mr. Koppe's conclusion that any *reductions* in emissions due to increases in heat rate from the other work done at the Armstrong units in the 1994 and 1995 outages would have been offset by *increases* in emissions due to increased usage of those Armstrong units. *See* T.T., Sept. 20, 2010, at 110:23-111:3 (Mr. Koppe's conclusion). In addition, the *Ohio Edison* court recognized the validity of Mr. Koppe's argument. *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 879-880 (S.D. Ohio 2003). Accordingly, there is no evidence that the Armstrong PSD Projects should have been expected to improve unit efficiency and reduce emissions.

Coal Heat Content: Based on review of Allegheny's records, Dr. Rosen saw no reason to expect the heat content of the coal to change after the projects and accordingly held the heat content rates constant. T.T., Sept. 21, 2010, at 85:5-14. No witness disputed that conclusion.

Emissions Factors: Finally, Dr. Rosen correctly held both the SO_2 and the NO_x emissions factors constant. As for SO_2, his understanding of the regulations and guidance was that he could only give credit for an anticipated change in sulfur content if it was "federally enforceable." T.T., Sept. 21, 2010, at 85:22-86:8, 86:16-20; PTX 2149 (d); *see also* 40 C.F.R. § 52.21(b)(3)(vi)(*b*) [PTX 2210 (d)]. Because he saw no such federally enforceable restrictions, he held the SO_2 emissions factor constant in the post-project period. T.T., Sept. 21, 2010, at 87:15-20. For example, Allegheny's Title IV compliance plans, as set out on the first page of its Title IV permit applications, did not show any anticipated changes to sulfur content or any other relevant factor. PTX 1937 at AE_HQ_00594149, PTX 1939 at AE_HQ_00137223; PTX 1941 at PADEP_SW00005552; PTX 1943 at AE_HQ_00137547; PTX 1945 at AE_HQ_00158989.

Similarly, Dr. Rosen correctly excluded the anticipated reductions of NO_x emissions due to Allegheny's installation of low-NO_x burners because those reductions do not qualify for inclusion in either the first or the second stage of the PSD calculations. The first stage of the PSD calculation looks only at the anticipated effect of the "physical change," that is, the PSD Projects, on future emissions. *See* 40 C.F.R. § 52.21(b)(3)(i)(*a*) [PTX 2210 (d)] (first stage calculates "[a]ny increase in annual emission *from a particular physical change*"). Allegheny's own documents show that the installation of the low-NO_x burners was not part of, or in any way related to, the PSD Projects. Allegheny installed the burners to comply with the RACT provisions of Title I. *See, e.g.*, PTX 260 *passim* (Armstrong); PTX 1084 at AE_DUN_00047441-AE_DUN_00047442; PTX 1085 (Hatfield's Ferry 3); T.T., Sept. 23, 2010,

at 133:12-20 (testimony of Mr. Evans regarding installation at Mitchell 3). With regard to Hatfield's Ferry and Mitchell 3, Allegheny's capital work orders for the PSD Projects do not reference Clean Air Act compliance or NO_x emissions reductions as part of the purpose of the projects. *See*, *e.g.*, PTX 1930 at AE_HQ_017320; PTX 1931 at AE_HQ_00173847; PTX 1932 at AE_HQ_017985; PTX 1933 at AE_HQ_00567616; PTX 1934 at AE_HQ_00285925; PTX 1935 at R-3 06898. Similarly, the capital work orders for the RACT projects for Hatfield's Ferry and Mitchell 3 make no reference to the PSD Projects. *See*, *e.g.*, PTX 1085; PTX 1086. The documents therefore show no relationship between the PSD Projects and the low-NO_x burner installations. In fact, for four of the PSD Projects – the secondary superheater project at Hatfield's Ferry 1 and the lower slope projects at all three Hatfield's Ferry units – the installation of the low-NO_x burners took place a year or more before the PSD Project. *Compare* Docket Item 430 ¶¶ 23, 24, 25 (installation of low-NO_x burners at Hatfield 1 in fall 1994, Hatfield 2 in fall 1993, and Hatfield 3 in spring 1995) *with* PTX 2129 (PSD Projects at Hatfield 1 in fall 1997, at Hatfield 2 in fall 1999, and at Hatfield 3 in fall 1996).

As for the Armstrong units, later versions of the capital work orders for the PSD Projects reference the low-NO_x burner installation, but solely for the purpose of *distinguishing* that work as separate from the other work – replacement of the convection superheater, reheater , economizer and other components – that constitutes the PSD Project. *See* PTX 1924 at R-3 09513 (transferring work from the "boiler project" capital work order to the low-NO_x burner capital work order to "accurately segregate the components . . . required . . . to meet Nox compliance as mandated by the 1990 Clean Air Act Amendments"); PTX 1925 at R-3 10200 (low-NO_x burner work order *not* containing the PSD Project work). The original Armstrong work orders did not even mention the low-NO_x burner installation, as Allegheny had intended to

perform the Armstrong boiler work regardless of the 1990 Amendments. PTX 1926. Accordingly, since the installation of the low-NO_x burners was not part of the PSD Projects, any effects of those burners cannot be included in the first stage of PSD emissions calculations.

Nor can the reductions from the low-NO_x burners be included in the second stage of the PSD calculations, because the reductions are not creditable. As noted in Argument section IV.C.3.a.ii above, to qualify for netting, emissions reductions must be creditable, and to be creditable, the reductions must be (1) federally enforceable, (2) surplus, (3) permanent and (4) quantifiable. *See, e.g.*, 51 Fed. Reg. 43814, 43831-32 (Dec. 4, 1986); *see also* PTX 2149 (d) at 2.

The reductions from the low-NO_x burners were neither federally enforceable at a relevant time nor surplus. To be creditable, an emissions decrease must be federally enforceable "at and after the time that actual construction on the particular change begins." 40 C.F.R. § 52.21(b)(3)(vi)(*b*) [PTX 2210 (d)]; *see also* 55 Fed. Reg. 7713, 7713-14 (Mar. 5, 1990) (denial of PSD permit because applicant took credit for an emission reduction that was not federally enforceable). As EPA stated specifically with regard to RACT NO_x requirements in Pennsylvania: "[t]he source becomes subject to federally enforceable requirements only after EPA approves a subsequent SIP revision incorporating the source-specific RACT regulations promulgated by the state." 60 Fed. Reg. 2912, 2914 (Jan. 12, 1995).

None of the RACT reductions were federally enforceable when construction on the PSD Projects began, however, because EPA did not approve the RACT reductions until after construction had begun, as the following table shows:

Project	Date PSD Project Began[51]	Effective Date of EPA RACT Approval[52]
Armstrong 1: Radiant Side and Convection Side	February 1995	October 1995
Armstrong 2: Radiant Side and Convection Side	February 1995	October 1995
Hatfield 1: Lower Slope	October 1997	July 2007
Hatfield 1: Secondary Superheater Outlet Headers	October 1997	July 2007
Hatfield 2: Pendant Reheater	September 1994	July 2007
Hatfield 2: Lower Slope	September 1999	July 2007
Hatfield 3: Lower Slope	September 1996	July 2007
Mitchell 3: Lower Slope	October 1994	October 2001

However, even if the projected emissions reductions from the RACT projects had been federally enforceable before Allegheny began construction on the PSD Projects, those reductions would not have been surplus. An emissions decrease is not surplus if it is "used by the source to meet any other regulatory requirement." 51 Fed. Reg. at 43832. As Allegheny itself states, the projected NO_x reductions that Allegheny contends Dr. Rosen should have credited were those that Allegheny relied upon to meet its RACT requirements. Docket Item 234-2 at 17. Because the regulations bar such "double counting," PTX 173 at 3 (EPA legal memorandum), the projected reductions were not surplus and could not be used for netting. The law does not allow Allegheny to evade stringent PSD/BACT standards on the order of 0.15 lb./million BTU, which would be imposed upon a finding that the projects were subject to PSD requirements, because it met weaker RACT standards on the order of 0.50 lb./million BTU. *Compare* PTX 1921 (d) at 1 (PA DEP setting NO_x BACT limit of 0.15 lb./million BTU for coal-fired plant

[51] Dates used in this column are found in PTX 2129, second column.

[52] Dates used in this column are found at 60 Fed. Reg. at 40292 (Armstrong); 66 Fed. Reg. at 52333 (Mitchell); 72 Fed. Reg. at 31749 (Hatfield's Ferry).

in 1995) *with* PTX 1916 at AE_HQ_00595046, ¶ 7 (setting NO_x RACT limit of 0.58 lb./million BTU for Hatfield's Ferry in 1995), PTX 1917 at AE_HQ_00595178, ¶ 5 (setting NO_x RACT limit of 0.45 lb/million BTU for Armstrong in 1995), PTX 1918 at AE_HQ_006078, ¶ 16 (setting NO_x RACT limit of 0.45 lb./million BTU for Mitchell 3 in 1995).

Dr. Rosen accordingly held the NO_x emissions factor constant as between the pre-project and post-project periods. He did so in two ways. In his "high NO_x" calculations, he used the high NO_x emissions factor, representing the state of affairs before the low-NO_x burners had been installed, for both the pre-project and post-project periods. T.T., Sept. 21, 2010, at 88:23-89:2. Analogously, in his "low NO_x" calculations, he used the low-NO_x emissions factor, representing the state of affairs after the low-NO_x burners had been installed, for both the pre-project and post-project periods. *Id*. at 89:2-4. Both calculations exclude the reduction in emissions due to the low-NO_x burners. T.T., Sept. 21, 2010, at 89:12-19.

With respect to the Hatfield's Ferry 1 secondary superheater outlet header and lower slope projects and the Hatfield's Ferry 2 lower slope project, plaintiffs respectfully ask the Court to find that Allegheny is liable for PSD NO_x violations based on the low-NO_x figures because the low-NO_x burners were in place during the pre-project baseline period that Dr. Rosen selected.

With respect to the remaining projects, plaintiffs respectfully ask the Court to find Allegheny liable based on the high-NO_x figures, since the high-NO_x burners were place during Dr. Rosen's pre-project baseline period. Plaintiffs note, however, that for the Armstrong PSD Projects and the Hatfield's Ferry 3 lower slope project, both the high-NO_x and low-NO_x calculations show significant net emissions increases.

iii. Dr. Rosen's Calculations of the Net Emissions Increases

Once Dr. Rosen had the pre-project and anticipated post-project emissions figures, he calculated the anticipated change in emissions from the project by subtracting the former from the latter, consistent with 40 C.F.R. § 52.21(b)(3)(i)(*a*). T.T., Sept. 21, 2010, at 90:3-93:22 (walking through one calculation). As for the netting phase of the PSD calculations, neither plaintiffs nor Dr. Rosen identified any contemporaneous, creditable emissions reductions at the Armstrong, Hatfield's Ferry or Mitchell plants that qualified for netting under 40 C.F.R. § 52.21(b)(3)(i)(*b*), and accordingly Dr. Rosen did not make any netting adjustments to his PSD calculations. T.T., Sept. 21, 2010, at 186:10-25; *see also* Argument section IV.C.3.c.ii above (explaining why emissions reductions for low-NO_x burners did not qualify for netting).

4. Allegheny Did Not Perform Emissions Analyses Consistent with the PSD Regulations

Allegheny presented no evidence that it ever performed emissions projections consistent with the PSD regulations for the PSD Projects. There is no evidence that Allegheny ever attempted to evaluate the effect of the Hatfield's Ferry or Mitchell 3 PSD Projects on annual emissions, let alone tried to perform an emissions projection consistent with the PSD regulations. Allegheny's witness, Dale Evans, testified that he had not performed any emissions analysis for the Mitchell 3 project or any other. T.T., Sept. 23, 2010, at 135:18-21. Neither Mr. Colby nor Mr. Maiden testified that Allegheny had ever applied an annual emissions test for the Hatfield's Ferry or Mitchell 3 PSD Projects, let alone had performed a calculation consistent with the PSD regulations. T.T., Sept. 23, 2010, at 137:17-220:13 (entirety of testimony of Mr. Colby); T.T., Sept. 27, 2010, at 109:7-174:8 (entirety of Mr. Maiden's testimony). To the contrary, Mr. Colby erroneously believed that the relevant emissions test required an increase in the hourly rate of emissions rather than an increase in the annual rate of emissions. William Maiden also operated

under the same erroneous understanding of the emissions standard when he testified that the projects would not increase emissions because they would not increase the units' steaming rate, which relates only to a unit's hourly emissions rate, T.T. Sept. 27.,2010, at 125:3-23; T.T., Sept. 23, 2010 at 157:5-17.. There is no written documentation of any emissions calculations under any standard relative to the Hatfield's Ferry or Mitchell PSD Projects or even of Mr. Colby's and Mr. Maiden's erroneous conclusion that no calculations were needed.

For the Armstrong work, while Allegheny at least in theory attempted to evaluate the effect of those projects on annual emissions, that attempt was not consistent with the PSD regulations and was otherwise unreliable. In 1993, in the "Mooney memorandum," an Allegheny maintenance engineer named Jeff Mooney evaluated whether the totality of the work anticipated during the 1994 and 1995 outages at Armstrong should have been expected to increase annual emissions. *See* PTX 177. As noted in Argument section II.D.4 above, Mr. Mooney was an inexperienced junior employee.

In the memorandum, Mr. Mooney determined that SO_2 emissions could have increased based on Allegheny's expectation of improved availability after the projects. *Id.* at AE_ARM00132856. But he concluded that heat rate improvements due to the projects would reduce emissions by approximately the same amount, so that the projects, on balance, would not be expected to increase annual SO_2 emissions. *Id.* As for NO_x, Mr. Mooney concluded that emissions would decrease based on his assumption that Allegheny was entitled to credit for reductions due to the installation of the low-NO_x burners. *Id.*

Mr. Mooney's conclusions were wrong, however, as a matter of law and fact. First, the emissions analysis in the memorandum was not consistent with the PSD regulations because it did not use a two-year pre-project baseline period for each unit. Instead, Mr. Mooney used

annual data for both units from the preceding five years and, without explanation or justification, eliminates from his calculations the two years with the longest outages and thus the lowest availability. T.T., Sept. 20, 2010, at 105:18-23. As Mr. Koppe explained, Mr. Mooney's removal of the two years of worst performance understated the availability increase from the work. If Mr. Mooney had included all the years, the availability increase from the projects would have been substantially greater – 7.7 percent rather than 4.6 percent. T.T., Sept. 20, 2010 at 104:13-106:10. Mr. Mooney's analysis also improperly gives Allegheny credit for the emissions reductions from the low-NO_x burners: he nowhere raises the netting issue, let alone performs any regulatory analysis to see if the NO_x reductions qualified for netting.

Mr. Mooney's analysis also erred in how he calculated the expected efficiency increase, because he miscalculated the pre-project efficiency level. *Id.* at 107:9-108:20. Using Mr. Mooney's approach but correcting for his errors in calculating the changes in availability, Mr. Koppe determined that the projects should each have been expected to increase SO_2 emissions by 475 tons per year, far different than the emission increase of zero tons that Mr. Mooney found. *Id.* at 109:4-22. Correcting for both the availability and efficiency errors, Mr. Koppe calculated an expected SO_2 emissions increase of 650 tons per year. *Id.* at 109:18-110:5.

Unlike many other Allegheny memoranda, this memorandum is addressed and cc'd to just one person – Mr. Colby – and there is no evidence that anyone from Allegheny's environmental staff ever saw this memorandum, let alone had any input into it. As Mr. Mooney acknowledged, the environmental department "really should have been making [the] call" about NSPS and PSD applicability, not him. D.T. (Jeff Mooney), Aug. 22, 2007, at 151:20-24.

5. Allegheny Has Not Complied with the PSD Requirements

Plaintiffs have met their burden on this element because Allegheny has not obtained a PSD permit or plan approval for any of the PSD Projects and did not operate the Armstrong, Hatfield's Ferry or Mitchell 3 units subject to BACT after completion of those projects. *See* PTX 2 ¶¶ 134, 136, 144, 146, 148 (Armstrong 1); *id.* ¶¶ 198, 200, 208, 210, 212 (Armstrong 2); *id.* ¶¶ 287, 289, 297, 299, 301 (Hatfield's Ferry 1 secondary superheater outlet headers and lower slope panels); *id.* ¶¶ 309, 311, 319, 321, 323 (Hatfield's Ferry 2 pendant reheater and lower slope panels); *id.* ¶¶ 331, 333, 341, 343, 345 (Hatfield's Ferry 3 lower slope panels); *id.* ¶¶ 379, 381, 389, 391, 393 (Mitchell 3).

D. <u>Allegheny's Defenses and Counterarguments to the PSD Claims Fail</u>

1. The Methodology Dr. Rosen Used and His Results Are Legally Correct and Reasonable on the Facts of the Case

At trial, Allegheny's witnesses offered several criticisms of Dr. Rosen's opinions, but all of those criticisms are meritless.

a. The High-Two-of-Five Approach to Selecting Baseline Periods Is Not Consistent with the Law and Otherwise Not Appropriate

The contention of Allegheny's expert Frank Graves that the "high two of five" approach to selecting a baseline period is appropriate, while Dr. Rosen's "average generation" approach is not, is wrong. *See, e.g.*, T.T., Sept. 22, 2010, at 22:2-23:4. While the average generation approach looks at the twenty-four month period during the five years before the project with the *average generation* amount, the high-two-of-five approach looks at the twenty-four month period with the *highest emissions* amount. T.T., Sept. 21, 2010, at 97:15-98:4.

As noted above, the average generation approach Dr. Rosen used has been adopted by one court, is consistent with the requirement that the baseline period be "representative of

normal source operations," and is fair. *See* Argument section IV.C.3.c.i above. The high-two-of-five approach has none of these merits. No court has ever adopted the high two of five approach, and the *Ohio Edison* court explicitly rejected it because there was no evidence the relevant PSD permitting agency in that case had allowed the use of that approach for the projects at issue. *Ohio Edison*, 276 F. Supp. 2d at 881. Allegheny, like the Ohio Edison utility, has presented no evidence that PA DEP approved Allegheny's use of the high-two-of-five approach for the PSD Projects. Allegheny may argue that PA DEP accepts the high-two-of-five approach, but the agency only does so if the utility asks the agency for approval to use that baseline and presents sufficient factual support. D.T. (Krishnan Ramamurthy 30(b)(6)), Jan. 10, 2008, at 28:15-30:1. Allegheny did not meet those factual predicates, however, since Allegheny never raised the issue with PA DEP. Indeed, there is no evidence that Allegheny or anyone else ever knew of the high-two-of-five approach in the 1990s before the last PSD Project in this case was undertaken. *See, e.g.*, T.T., Sept. 22, 2010, at 124:14-125:7 (testimony of Mr. Graves that he had seen no documents before 1999 referencing the high two-of-five approach).

The high-two-of-five approach also fails to select a baseline period that is "representative of normal source operation," as required by the regulations. 40 C.F.R. § 52.21(b)(21)(ii) [PTX 2210 (d)]; 57 Fed. Reg. at 32325 [PTX 2217 (d)]; *Ohio Edison*, 276 F. Supp. 2d at 869, 881. The high-two-of five approach selects the baseline period with the maximum emissions value, which is an extreme value. T.T., Sept. 22, 2010, at 126:5-21 (Mr. Graves); *see also* Merriam-Webster's Collegiate Dictionary at 413 (10^{th} Ed. 1993) [PTX 2220 (d)] (definition of the noun "extremum"). Because an extreme value "exceeds the ordinary, usual or expected," *id.* (definition of the adjective "extreme"), the "extreme" high-two-of-five approach is far from being "representative of normal source operation." That approach is also biased in favor of

industry, because it tends to select higher past emissions levels, T.T., Sept. 22, 2010, at 21:22-23, and as a result will tend to give the smallest possible projected emissions increases

In any event, even if the Court should rule that the high-two-of-five approach is acceptable and the average generation approach is not, Dr. Rosen prepared emissions projections under the high-two-of five-approach. T.T., Sept. 21, 2010, at 97:6-100:6; 101:24-102:1; 102:20-104:5. Those figures are as follows:

Project	**SO_2**	**NO_x (High NO_x)**	**NO_x (Low NO_x)**
Armstrong 1: Radiant Side and Convection Side	286	72	31
Armstrong 2: Radiant Side and Convection Side	600	215	97
Hatfield 1: Lower Slope	896	335	125
Hatfield 1: Secondary Superheater Outlet Headers	221	83	31
Hatfield 2: Pendant Reheater	231	0	0
Hatfield 2: Lower Slope	919	16	7
Hatfield 3: Lower Slope	1,244	456	203
Mitchell 3: Lower Slope	8	48	31

PTX 2175. Thus, under the alternative "high 2 of 5" baseline assumption, Dr. Rosen calculated significant net emissions increases of SO_2 for all of the PSD Projects except the Mitchell 3 project, for which plaintiffs previously withdrew their SO_2 claims. Dr. Rosen also calculated significant net emissions increases of NO_x under his high NO_x approach for the following four PSD Projects: Armstrong 1, Armstrong 2, Hatfield's Ferry 3 lower slope and Mitchell 3 lower slope. Under the low NO_x approach, Dr. Rosen calculated significant net emissions of NO_x for the Hatfield's Ferry 1 lower slope project.

b. Allegheny's Critiques of Mr. Koppe's Availability Analyses Lack Merit

i. Mr. Koppe Does Not Automatically Assume Increases in Availability

Allegheny may argue that Dr. Rosen's emissions projections are invalid because they rely on Mr. Koppe's purportedly "automatic" projections of increased availability for projects.

See, e.g., T.T., Sept. 13, 2010, at 27:18-22**.** But there is no evidence that Mr. Koppe "automatically" assumes availability increases. Mr. Koppe testified that many projects would not be expected to increase availability. T.T., Sept. 20, 2010, at 15:1-16:22 (routine maintenance would not increase availability), 58:18-24 (millions of routine maintenance projects). To the extent that he projected availability increases for all of the PSD Projects at trial, that was the result of plaintiffs' elimination of projects where the evidence did not support an expectation of increased availability: "[t]he ones that went forward were predictions of increases because if there weren't a prediction of increase, they didn't go forward." *Id.* at 145:25-146:2; *see also id.* at 145:6-10 ("It is -- it is true that all the projects that went forward in those cases were because we found an increase in emissions. There were projects that were dropped because there were not increases in emissions -- or not expected to be increases in emissions."). Indeed, Allegheny knows that plaintiffs withdrew one of the projects in the complaint because Mr. Koppe concluded that no availability increase should have been expected. T.T., Sept. 21, 2010, at .64:20-65:12 (explaining that Mr. Koppe had not found an availability increase for the Hatfield 2 secondary superheater outlet header project); Docket Item 245 ¶ 1(a) (stipulated withdrawal of portions of claims relating to that project).

ii. There Is No Evidence that Decreased Availability from Other Components Would Have Offset Increased Availability from the PSD Projects

Notwithstanding the evidence in its own 1990s statements about the projects, Allegheny maintains that the Hatfield's Ferry and Mitchell 3 PSD Projects should not have been expected to increase unit availability. T.T., Sept. 22, 2010, at 107:12-16[53] As noted above, Mr. Koppe's

[53] Allegheny admitted that it expected the Armstrong work to improve availability. T.T., Sept. 22, 2010, at 107:17-19.

conclusions that the PSD Projects should have been expected to increase unit availability depend on two things: (1) the effect of the PSD Project itself on the unit's availability, and (2) the effect of "everything else" on the unit's availability. *See*, *e.g.*, T.T., Sept. 20, 2010, at 73:2-74:12. With regard to the first issue Mr. Koppe examined, as noted above, Allegheny's own documents repeatedly state that Allegheny expected the PSD Projects to reduced forced outages and increase availability, and in fact in many cases calculate the reduction in outage time that Allegheny expected from the PSD Projects. *See* Argument section IV.C.3.b above; *see also* T.T., Sept. 23, 2010, at 126:1-128:25 (testimony of Mr. Evans that he expected the new lower slope panels at Mitchell 3 to perform better than the ones replaced in the PSD Project).

Accordingly, the success or failure of Allegheny's argument turns on the second aspect of Mr. Koppe's analysis: whether the performance of "everything else" at the unit should have been expected to worsen at the same time as a PSD Project, and to such an extent that the availability losses due to that sudden worsening overwhelmed the availability gains from the PSD Project. There is no evidence to support that conclusion.

Former Allegheny senior executive Clark Colby and current Allegheny employee Paul Kramer testified about the variety and frequency of forced outages at Allegheny's coal-fired generating units. *See, e.g.*, T.T., Sept. 23, 2010, at 19:3-22:10; 24:6-29:6; 160:20-161:4, 180:7-182:9. As Mr. Colby put it, trying to prevent equipment failures and keep a generating unit operational is like trying to catch thousands of ping-pong balls before they float over a waterfall. T.T., Sept. 23, 2010, at 189:16-190:12.

But the issue is not whether, in general, components at a generating unit can and do fail over time. No one disputes that. The issue is whether, for some reason, the average failure rate of the components that are not being replaced as part of a PSD Project should, for some reason,

be expected to suddenly worsen and reduce availability *at the same time* as the PSD Project is expected to improve availability.

Thus, to use Mr. Colby's analogy, the question is not simply whether there are 1,000 ping pong balls flowing down the river each hour. Rather, the question is this: if 1,000 ping-pong balls are flowing down the river each hour, and Allegheny expects a PSD Project to reduce that flow by 30 balls, a reduction of three percent, is there any evidence that something else – *at the same time* – is going to increase the flow by an additional 30 or more balls, so that the total flow of balls does not decrease. Or, to put the problem into a more concrete real-world context: given, for example, that Allegheny expected the Hatfield's Ferry 3 lower slope project to increase availability by 256 hours – about three percentage points – in the two years following the project, PTX 633 at R-3 02096 (one-third of the 768 hours for all three Hatfield's Ferry lower slope projects), was there any evidence that the condition of other components at that unit was going to suddenly deteriorate, *at the same time as the lower slope project*, so as to reduce the unit's availability by 256 hours or more – about three percent -- over those same two years, so that the net effect would be reduced, not improved, availability.

The answer is no: Allegheny presented no probative, credible evidence at trial as to why someone would have expected other equipment at a unit to become measurably less reliable at the same time as a PSD Project made one or more major components measurably more reliable. *See*, *e.g.*, T.T., Sept. 22, 2010, at 99:2-22 (Allegheny expert Mr. Graves unable to identify a reason why that Allegheny would have expected a three percent reduction in availability due to other components at a Hatfield's Ferry unit at the same time that Allegheny expected a three percent improvements in availability from the lower slope project).

Allegheny only presented evidence of one possible reason why it might have been reasonable to expect reductions in availability at the same time as the PSD Projects: increased tube corrosion or wastage from the installation of low-NO_x burners. For example, Mr. Maiden testified that Allegheny had experienced corrosion from low-NO_x burners in the side walls at its Pleasants power station in West Virginia and had evaluated remedial measures such as adding a protective spray covering or a welded overlay. T.T., Sept. 27, 2010, at 116:19-21, 117:16-17; *see also id.* at 166:20-168:3 (Mr. Maiden); T.T., Sept.23, 2010, at 52:9-16 (Mr. Kramer).

This argument fails, however, because Allegheny has not provided the necessary supporting evidence. To succeed on its defense that unit availability should not have been expected to increase, Allegheny has to prove that expected availability losses from the low-NO_x burners would have been at least as large as the expected availability gains from the PSD Projects, so that the combined effect on unit availability would have been zero or negative. Accordingly, Allegheny has to present evidence of the magnitude of availability losses, if any, it expected from the low-NO_x burners. But Allegheny has presented no such evidence.

Allegheny's witness, Mr. Maiden, testified that Allegheny had become aware of the corrosion problem at its Pleasants plant in the 1980s and had taken steps to address it by metalizing or weld overlays. T.T., Sept. 27, 2010, at 116:2-117.17. At Hatfield's Ferry, Allegheny took similar steps to reduce or eliminate that problem during the 1990s. Sometime in approximately 1995 or 1996, at the three Hatfield's Ferry units, Allegheny installed tube panels with a welded overlay "in those areas of the boilers[ ] which suffered the highest wastage rates after the low-NOX conversion." DTX 1324 at AE_HF00080426 ("Hatfield's Ferry Power Station has approximately five years experience with the installation of weld clad water-wall panels in all three boilers") (this Allegheny memorandum is undated, but was probably written in

2000 or early 2001, given that it evaluates whether Allegheny could perform certain work during outages in 2001 or later).

None of Allegheny's exhibits or trial witnesses, however, provide an estimate of the magnitude of the availability losses, if any, that Allegheny expected from low-NO_x burner wastage before undertaking the Hatfield's Ferry PSD Projects. In particular, there is no evidence of the magnitude of expected availability losses from the low-NO_x burners, if any, in light of Allegheny's installation of protective equipment designed to reduce or eliminate those availability losses. Without evidence of the expected magnitude of such availability losses, Allegheny has no proof that the expected availability losses from the low-NO_x burners were large enough to offset the expected availability gains from the PSD Projects.

An example may help to illustrate the point. As noted above, before undertaking the lower slope project at Hatfield's Ferry 2 in 1999, Allegheny expected the lower slope project to increase availability an average of 256 hours at each unit. According to Mr. Koppe's review of Allegheny's outage records, Allegheny should have expected that project to increase availability by a smaller amount, 143 hours. Allegheny's defense, however, requires it to prove that the 256 hours/143 hours of expected increased availability from the lower slope work would have been offset by at least 256 hours/143 hours of expected reduced availability from the low-NO_x burner installation. But there is no evidence indicating whether Allegheny believed that the low-NO_x burners would reduce availability by zero hours, 10 hours, 100 hours or 500 hours. As a result, there is no evidence to support Allegheny's argument that the unit availability would not have increased because the negative effect of the low-NO_x burners would have exceeded the positive effect of the project.

In fact, Allegheny concedes that it expected unit availability to increase after the Armstrong projects even though low NO_x burners were installed during the very same outages, and Allegheny was purportedly aware at that time, according to Mr. Maiden's testimony, that low NO_x burners could have an adverse affect on boiler performance. T.T., Sept. 22, 2010, at 107:17-19 (admitting expected availability increase).

As for Mitchell 3, Allegheny employee Dale Evans mentioned the low-NO_x corrosion issue in passing, but did not specify how much of an availability loss, if any, Allegheny expected. T.T., Sept. 23, 2010, at 128:7-21. For the Mitchell 3 PSD Project, based on Mr. Koppe's analysis, plaintiffs contend that Allegheny should have expected an availability increase of at least 194.1 hours. *See* PTX 2129 (Dr. Rosen chose baseline period of June 1992 through May 1994 for the Mitchell 3 lower slope project); PTX 83 (four outages of a total of194.1 hours duration during the June 1992-May 1994 baseline period). Because there is no evidence of the magnitude of the availability loss, if any, that Allegheny expected from the low-NO_x burners at Mitchell 3, there is no evidence that Allegheny should not have expected unit availability to increase by the 194 hours because of the PSD Project.

In addition to the lack of probative evidence, Allegheny's argument fails for another reason: for three of the Hatfield's Ferry PSD Projects, Dr. Rosen's calculations would have incorporated the effect of low-NO_x burner tube wastage, if any, because the burners were installed before the pre-project baseline period that Dr. Rosen used. For the two PSD Projects at Hatfield's Ferry 1, Dr. Rosen used a September 1995 – August 1997 pre-project baseline period. PTX 2129. Allegheny, however, installed the low-NO_x burners at that unit before the baseline period, in the fall of 1994, Docket Item 430 ¶ 23, so any increased wastage would have been incorporated in Dr. Rosen's pre-project (and post-project) calculations. For the lower slope PSD

Project at Hatfield's Ferry 2, Dr. Rosen used a February 1997 – January 1999 baseline period. PTX 2129. Allegheny installed the low-NO_x burners at that unit in the fall of 1993, however, Docket Item 430 ¶ 24, so, again, any increased wastage would have been incorporated in Dr. Rosen's calculations. Thus, for those three projects, Allegheny's argument that the low-NO_x burners would have made things worse after the PSD project has no basis.

iii. Allegheny in Fact Predicted Past-to-Future Increases in Unit Availability

Allegheny witness William Maiden testified that he performed "future-to-future" analyses regarding expectations of increased unit availability and never expected that unit availability would increase on a past-to-future basis, as required under the PSD regulations. T.T., Sept. 27, 2010, at 148:23-149:9 (performed future-to-future analyses), 155:2-9 (never expected past-to-future increases in availability). In fact, however, Allegheny anticipated past-to-future unit availability increases.

When evaluating component-replacement projects like the PSD Projects, Allegheny and other utilities generally analyze the effects of the project on a future-to-future basis. A future-to-future analysis compares a *future* baseline with a *future* alternative. The baseline is a hypothetical future where the project *is not* performed, so that the problems caused by the flawed component continue to occur, and may worsen. The alternative is a hypothetical future where the project *is* performed, so that, because the flawed component is replaced, the problems are due to the component are reduced or eliminated. T.T., Sept. 20, 2010, at 17:19-18:15 (Mr. Koppe); T.T., Sept. 23, 2010, at 175:3-15, 175:23-177:2 (Mr. Colby).

The PSD regulations, on the other hand, require a *past*-to-future analysis. For these calculations, the baseline consists of an actual time period in the past. The alternative, however, is the same as in the future-to-future analysis: a hypothetical future where the project is

performed, so that the expected benefits of the project are realized. Thus, the difference between the two approaches is in the baseline: one baseline is the *future* without the project, the other baseline is the *past* without the project.

While Allegheny expected future to future availability improvements, it also expected past-to-future improvements. For the Armstrong projects, Mr. Mooney calculated the increase in availability by first calculating an average based on Allegheny's historical availability levels and then calculating the expected availability assuming the project was performed. PTX 178 at AE_ARM00132602. This is a past-to-future analysis.

Allegheny's economic evaluations for the Hatfield's Ferry lower slope and pendant reheater projects reflect its expectation of past-to-future availability increases. For the lower slope panel projects, Allegheny's economic analysis, while nominally a future-to-future analysis, is identical to a past-to-future analysis because Allegheny assumed that the annual outage rate for the lower slope panels in the hypothetical future – on average, eight outages of four days a piece among the three units – was the same as the past outage rate. *Compare* PTX 633 at R-3 02095 ("BOILER TUBE LEAK REPORTS INDICATE THAT THE LOWER SLOPE TUBE FAILURES CAUSE EIGHT FORCED OUTAGES PER YEAR AND EACH FORCED OUTAGE AVERAGES FOUR DAYS OF DOWNTIME") *with id.* at R-3 02096 (applying the eight outage/four day assumption in the future-to-future analysis). As for the Hatfield's Ferry pendant reheater project, Allegheny's economic future-to-future economic analysis assumed that the project would eliminate three outages per year. PTX 715 at AE_DUN_00194044. Two of those outages were not based on the historical failure rate of the reheater, but instead predicted that the performance of the pendant reheater would degrade further in the future. *Id.* at AE_DUN_00194043. One of the outages that Allegheny expected the project to eliminate,

however, was based on the past failure rate of one outage per year for that component. *Id.* Accordingly, Allegheny expected that that the pendant reheater project would improve availability on a past-to-future basis by 72 hours: one outage of three days' duration.

Even for the Mitchell 3 PSD Project, although Allegheny never performed an economic analysis, Allegheny expressed the justification for the project in terms of past performance, with no suggestion that the future hypothetical performance without the PSD Project would be any different: "[d]uring the past five and a half years there have been an average of 3.8 leaks per year in this ash hopper area." DTX 461 at AE_HQ_00285967. Thus, Allegheny itself expected past-to-future availability increases for the PSD Projects.

For the Hatfield's Ferry 1 fall 1997 secondary superheater outlet header project, while Allegheny's original economic analysis from early 1995 did not reflect the past outage history of the unit, Allegheny nonetheless subsequently experienced three outages caused by the outlet headers in 1995 and 1997 that the project would have eliminated. *See* PTX 565 at AE_DUN_00412488.

c. There Is No Legal or Factual Basis to Incorporate Purported Reductions in Utilization Due to Installation of Scrubbers at Harrison, Additional PURPA Capacity, and Demand Management Activities in the PSD Emissions Projections

Allegheny wrongly contends that Dr. Rosen should have incorporated in his calculations reductions in utilization of the Armstrong, Hatfield's Ferry and Mitchell 3 units that Allegheny purportedly anticipated before the projects. According to Allegheny, it expected those reductions in utilization for three reasons. First, Allegheny claims that it expected to import more electricity to its service area from power stations owned by others and constructed under the authority of the Public Utilities Regulatory Policies Act, or PURPA, 16 U.S.C. §§ 2601-2645. *See*, *e.g.*, T.T., Sept. 28, 2010, at 149:17-150:3 (closing statement). Second, Allegheny

claims that it expected to reduce the overall demand for electricity by its customers through its "load modification" or "load management" or program. *See, e.g.*, T.T., Sept. 28, 2010, at 150:5-9 (closing statement). Third, Allegheny claims that it expected to use its three Pennsylvania power stations less because it expected to use its Harrison power station in West Virginia more. According to Allegheny, it expected to use the Harrison plant more because it installed equipment to reduce SO_2 pollution, known as flue gas desulfurization equipment or "scrubbers," at the plant to comply with Title IV of the Clean Air Act. *See, e.g.*, T.T., Sept. 22, 2010, at 166:3-167:11 (Mr. Skrgic).

Allegheny's argument that Dr. Rosen should have incorporated these purported anticipated reductions in unit utilization fails, however, because it is contrary to law and not adequately supported in the record. As a legal matter, any emissions reductions due to these factors would not have qualified for inclusion in PSD emissions calculations. As a factual matter, Allegheny's arguments fail for the same reason that its arguments about unit availability failed: while Allegheny presented some generic testimony on these subjects, Allegheny did not present evidence that established that these three factors would have had a material effect on emissions from the Armstrong, Hatfield's Ferry or Mitchell 3 units after the projects.

i. Any Anticipated Reductions in Generation Resulting from PURPA Imports, Allegheny's Load Modification Program and the Installation of the Harrison Scrubbers Do Not Qualify for Inclusion in the PSD Emissions Projections

Allegheny's contention that Dr. Rosen should have included these reductions in utilization in his emissions projects fails because, as a matter of law, none of the alleged reductions qualifies for inclusion in either the first stage or the second stage of PSD emissions calculations. As noted in Argument section IV.C.3.a.i above, the first stage of the PSD emissions calculation looks at the anticipated effect of the "physical change," in this case, one of

the PSD Projects, on future emissions. *See* 40 C.F.R. § 52.21(b)(3)(i)(*a*) [PTX 2210 (d)] (first stage calculates "[a]ny increase in annual emission *from a particular physical change* . . . at a stationary source"). There is no evidence that PURPA imports, Allegheny's load modification programs or installation of the Harrison scrubbers were part of, or in any way related to, the PSD Projects. Allegheny would have made efforts to import PURPA generation, reduce system load, and install scrubbers at Harrison to comply with Title IV of the Clean Air Act whether or not it undertook the PSD Projects. Conversely, Allegheny would have undertaken the PSD Projects whether or not it engaged in any of those three efforts. Thus, because Allegheny's PURPA imports, load modification program and Title IV activities were not part of the "physical change" at the units, they would not qualify for inclusion in stage one of the PSD calculations.

Nor do any effects of PURPA imports, the load modification program or increased generation at Harrison qualify for netting, the second stage of PSD emissions projections. As noted in Argument section IV.C.3.a.ii above, to qualify for netting, emissions reductions must be creditable, and to be creditable, the reductions must be (1) federally enforceable, (2) surplus, (3) permanent and (4) quantifiable. *See*, *e.g.*, 51 Fed. Reg. 43814, 43831-32 (Dec. 4, 1986).

To start, the purportedly anticipated reductions in generation at Allegheny's Pennsylvania units due to PURPA imports and load management efforts were not federally enforceable. Allegheny had an obligation to purchase electricity from PURPA generators, and had expectations regarding the amount of the reductions in system-wide generation at its power stations that the PURPA imports would cause. *See*, *e.g.*, PTX 1223 at AE_DUN_00381094 (table in West Penn Power's 1995 annual report to the Pennsylvania Public Utility Commission setting out expected imports of PURPA electricity). However, those estimates were not federally enforceable: if PURPA imports were lower than expected, no synthetic minor permit

or other federally-enforceable document prevented Allegheny from increasing generation at Armstrong, Hatfield's Ferry, Mitchell 3, or any or all of those units, to make up for the missing PURPA power and, in so doing, increase emissions from those units.

Similarly, Allegheny set "goals" for the amount of reduction in electricity demand it hoped to achieve through its load management program. *See*, *e.g.*, PTX 1223 at AE_DUN_00381113 (last column of table setting out Allegheny's 1995 "goals" for reducing electricity demand from 1995 through 2014). But those goals were not in any way legally binding. In fact, as Dr. Rosen indicated at trial, these programs were not very effective. T.T., Sept. 21, 2010, at 175:11-19. The amount of demand reduction that Allegheny actually obtained during the 1990s was only a small percent of its goal: for example, Allegheny only achieved about two percent of its 1995 load modification goal. *Compare* PTX 1223 at AE_DUN_00381113 (Allegheny setting goal of reducing electric demand in 1995 by 274,044,000 kilowatthours, equivalent to 274.0 gigawatt hours) *with* PTX 1224 at AE_DUN_00380679 (in May 1996, noting actual 1995 reduction in electric demand of 5,094,652 kilowatthours, or 5.1 gigawatt hours, approximately two percent of the goal established the preceding year). But in any event, as with the estimated amount of the PURPA imports, no synthetic minor permit or other legally-binding document made the estimated demand reduction through load management federally enforceable.

As for the purported reductions in utilization due to increases in generation at the Harrison power station, those did not qualify for netting because they did not meet any of the four requirements for creditability. This category of purported reductions in utilization, however, were not federally enforceable, quantifiable or permanent because they arose as a consequence of Allegheny's Title IV compliance actions. As noted in Background and Facts

section II.E above, the Title IV program set no fixed limit on Allegheny' generation or emissions: Allegheny could generate as much electricity as it wanted at any of its generating units, so long as it had a sufficient number of SO_2 emissions allowances, and Allegheny could buy allowances as necessary if it wanted to increase generation and emissions. So even if Allegheny did, at some point before a PSD Project, have an expectation that generation at the unit at which the project was being performed would decrease because generation at Harrison would increase, Allegheny could, at any time it wanted, decide to abandon those expectations and increase generation at the unit, either by transferring allowances from another Allegheny plant or buy buying additional allowances on the open market. Any anticipated utilization reductions were therefore not federally enforceable, quantifiable or permanent: Allegheny could increase generation at any time so long as it obtained more allowances.

Even if the anticipated utilization reductions had been federally enforceable, quantifiable and permanent, they still would not have qualified for netting, as they would not have been surplus. To be surplus, emissions reductions have to be in excess of other legal requirements: one cannot use an emissions reduction to meet one regulatory requirement and then "double count" the reduction by using it to net out of the PSD requirements. PTX 173 at 3; *see also* PTX 174 at 2; 51 Fed. Reg. 43814, 43832 (Dec. 4, 1986). But as Allegheny admits, the purported utilization reductions, and consequent emissions reductions, from the installation of the Harrison scrubbers were done to meet the Title IV requirements. Because there was no federally enforceable reduction beyond the Title IV requirements, any such expected reductions were not surplus. Accordingly, the purported generation and emissions reductions due to the Harrison scrubbers met none of the four requirements for creditability and therefore could not, as a matter of law, be incorporated in the second stage of Dr. Rosen's PSD emissions projections.

If Allegheny had really been willing to commit to binding reductions in utilization in order to avoid PSD requirements, it could and should have asked PA DEP for a synthetic minor permit. *See* Argument section IV.C.3.a.iii above. It did not. In particular, with regard to the installation of the Harrison scrubbers, Allegheny contends it did not need to meet the PSD SO_2 requirements of CAA Title I because it complied with Title IV. But "[i]n passing title IV, Congress did not suspend any requirements of title I," 57 Fed. Reg. at 32315 [PTX 2217 (d)]. Because the PSD regulations bar the use of the Title IV reductions in PSD calculations, Dr. Rosen was correct to exclude them from his emissions calculations.

ii. Allegheny Provides No Evidence that the Alleged Anticipated Reductions in Utilization Were Large Enough to Have Any Material Impact on Dr. Rosen's Projections

Even if the PSD regulations allowed one to include the purported expected decreases in utilization in PSD emissions projections, Allegheny presented no evidence that those decreases would have been sufficiently large to offset expected gains in availability. Although Allegheny's witnesses presented vague testimony claiming that the PURPA imports and load management efforts would reduce utilization of the Pennsylvania plants, they never provided specific information about how much generation Allegheny might have expected from those units, or whether the additional PURPA generation would have come on line at a relevant time -- at the time of the PSD Projects -- or at an irrelevant time many years before or after. *See, e.g.*, T.T., Sept. 23, 2010, at 187:9-188:12 (citing size of certain PURPA units but not indicating the amount of generation expected from them or when those units came on line).

Mr. Colby's testimony demonstrates this lack of evidence. He mentions a PURPA facility, the AES Beaver Valley plant, T.T., Sept. 23, 2010, at 188:2-4, but neglects to mention that the plant had started operation in 1987. PTX 1223 at AE_DUN_00381087. So whatever

impact that 1987 plant may have had on Allegheny's operations was already incorporated in Dr. Rosen's pre-project and post-project figures, all of which were for periods after October 1989. In sum, then, Allegheny has not demonstrated that the increases in PURPA imports and load management reductions during the relevant periods for this case were large enough to have a material effect on Dr. Rosen's calculations.

Allegheny's contention regarding the purported effect of the installation of the Harrison scrubbers to meet Title IV requirements suffers from the same lack of probative evidence. As a preliminary matter, Allegheny's historical documents – and in particular its Title IV compliance plans, as set out on the first page of its Title IV permit applications – did not show any anticipated, federally enforceable reduction in utilization due to the installation of the scrubbers. PTX 1937 at AE_HQ_00594149, PTX 1939 at AE_HQ_00137223; PTX 1934 at PADEP_SW00005552; PTX 1943 at. AE_HQ_00137547; PTX 1945 at AE_HQ_00158989. While Allegheny's witnesses at trial provided generic testimony claiming that Allegheny expected to use the Pennsylvania plants less after the installation of the scrubbers, no witness specified how much less. *See*, *.e.g.*, T.T., Sept. 22, 2010, at 163: 6-164:5, 165:25-167:11 (Mr. Skrgic); T.T., Sept. 23, 2010, at 186:10-187:8 (Mr. Colby); *see also* T.T., Sept. 22, 2010, at 42:6-43:13 (Mr. Graves). In the course of evaluating its compliance options under the 1990 Clean Air Amendments, Allegheny performed a variety of emissions analyses. *See, e.g.*, PTX 116 at AE_DUN-00606270- 277; PTX 1871 at AE_MIT00038651, AE_MIT00038652. None of these analyses show that Allegheny expected utilization at the Pennsylvania units to decrease, or by how much. The lack of such evidence suggests that, even if Allegheny at the time anticipated reductions in utilization, it did not believe those reductions to be of any noticeable magnitude. Thus, without evidence that Allegheny expected the installation of the

Harrison scrubbers to reduce utilization by a material amount, Allegheny has not established that Dr. Rosen failed to incorporate a material factor in his calculations.

In addition, for three of the PSD Projects, Allegheny's contention regarding the Harrison scrubbers lacks any foundation because the purported reduced utilization would have started before the pre-project baseline period Dr. Rosen used. Phase I of Title IV became effective on January 1, 1995, so that any reduction in utilization due to the installation and operation of the Harrison scrubbers occurred on or before that date. But for the two 1997 PSD Projects at Hatfield's Ferry 1, Dr. Rosen used a baseline period running from September 1995 through August 1997. PTX 2129. For the 1999 lower slope PSD Project at Hatfield's Ferry 2, Dr. Rosen used a baseline period running from February 1997 through January 1999. *Id*. Thus, for those three projects, Dr. Rosen's pre-project and post-project utilization factors would have incorporated the reduction in utilization, if any, due to the Harrison scrubbers.

Finally, as regards Mitchell 3, Allegheny's theory does not even make sense. Allegheny contends that the 1990 Amendments made running generating units with scrubbers more attractive then it had been before. *See*, *e.g.*, T.T., Sept. 22, 2010, at 42:6-43:13. If that were true, then Mitchell 3, which Allegheny had equipped with a scrubber in 1980, would also have become more attractive to run. *See* DTX 1052 at AE_HQ_00269725 (Mitchell 3 flue gas desulfurization system installed in 1980); T.T., Sept. 22, 2010, at 163:23-164:5. Thus, under Allegheny's theory, utilization of Mitchell 3 should have been expected to increase, not decrease.

d. Dr. Rosen's Conclusion That Increased Availability Would Lead to Increased Generation Is Reasonable and Consistent with Allegheny's Own Expectations

Allegheny contends that Dr. Rosen makes an "irrebuttable presumption" that expected increases in the availability of the units at issue in this case will very likely lead to an increase in the amount of electricity that those units generate. *See* Docket Item 126 at 10. But Dr. Rosen's assumption of a link between availability and generation is consistent with the case law, common sense and Allegheny's own documents from the 1990s.

As the Seventh Circuit recently stated, there is a "presumption" that increases in availability at baseloaded plants will result in increases in generation, "because baseload plants are designed to be run at or near full capacity." *United States v. Cinergy Corp.*, 623 F.3d 455, 460 (7th Cir. 2010). That presumption applies here because Allegheny operated the Armstrong, Hatfield's Ferry and Mitchell 3 units as baseloaded units in the 1990s.

The Seventh Circuit set out these descriptions of "baseload" and "cycling" units:

> Baseload equipment is operated virtually continuously. . . . Cycling equipment is operated on a regular or fairly regular basis, but not continuously, ... For example, such equipment might be needed daily during hours of high demand and then shut down at night.

Cinergy, 623 F.3d at 459. This distinction between baseloaded and cycling units is consistent with the testimony of Mr. Koppe, who defined a baseloaded electric generating unit as one that is operated all or most of the time that it is available. T.T., Sept. 20, 2010, at 11:14-19.

The *Cinergy* presumption applies here because the Armstrong, Hatfield's Ferry and Mitchell 3 units were baseloaded units in the 1990s. Allegheny itself characterized the Hatfield's Ferry and Mitchell 3 units as baseloaded in its GADS reports to NERC throughout the

1990s.[54] *See* PTX 1238 at 4 (Hatfield 1: lines 24-33, indicating status "1" in column J), at 4-5 (Hatfield 2: lines 49-58, indicating status "1" in column J), at 5 (Hatfield 3: lines 74-83, indicating status "1" in column J), at 6 (Mitchell 3: lines 106-115, indicating status "1" in column J); NERC, *Generating Availability System Data Reporting Instructions* at IV-7, (indicating that status "1" means "baseloaded"), *available at* www.NERC.com/files/GADS_DRI_Complete_Version_010111.pdf. The 2004 Sargent & Lundy consulting report that Allegheny commissioned and relied on at trial, *see*, *e.g.*, T.T., Sept. 23, 2010, at 11:7-19:10, stated that the Armstrong, Hatfield's Ferry and Mitchell 3 units had historically been run as baseloaded units. DTX 1052 at AE_HQ_00269605 (Armstrong), AE_HQ_00269695 (Hatfield's Ferry), AE_HQ_00269726 (Mitchell 3).

As further evidence, the Allegheny's GADS performance data regarding the "reserve shutdown" status of these units in the five years before the PSD Projects indicates that the units were baseloaded. Reserve shutdown status occurs when a generating unit is available – that is, the unit is mechanically able to operate – but the utility chooses not to run it. *See, e.g.*, T.T., Sept. 22, 2010, at 198: 25-199: 6; T.T., Sept. 23, 2010, at 28:7-12. Thus, a baseloaded unit would have a relatively small amount of reserve shutdown time, because it is run almost always when it is available. That was the case for the Armstrong, Hatfield's Ferry and Mitchell 3 units during the two-year pre-project baseline periods Dr. Rosen selected. As the following chart shows, the average annual reserve shutdown time during those periods ranged from zero days for Armstrong 2 to 16 days for Mitchell 3, meaning that Allegheny used the units almost all the time that they were available.

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[54] Allegheny did not provide GADS data for the Armstrong plant for the relevant time period in the early and mid-1990s.

Project	Baseline Period	Average Days Per Year in Reserve Shutdown[55]	Average Utilization Factor[56]
Armstrong 1: Radiant Side and Convection Side	Apr.. 1992 - Mar. 1994	0.6	90.2%
Armstrong 2: Radiant Side and Convection Side	Oct. 1989 - Sept. 1991	0.0	87.8%
Hatfield 1: Lower Slope	Sept. 1995 – Aug. 1997	9.8	79.3%
Hatfield 1: Secondary Superheater Outlet Headers	Sept. 1995 – Aug. 1997	9.8	79.3%
Hatfield 2: Pendant Reheater	Oct. 1990 – Sept. 1992	10.0	87.0%
Hatfield 2: Lower Slope	Feb. 1997 – Jan. 1999	6.0	76.1%
Hatfield 3: Lower Slope	Oct. 1992 – Sept. 1994	1.2	86.8%
Mitchell 3: Lower Slope	June 1992 – May 1994	16.0	68.8%

Fourth, the high utilization factors for the units in the pre-project baseline period further supports the conclusion that the units were baseloaded. Utilization factor represents the extent to which a unit is used when it is available, T.T., Sept. 21, 2010, at 42:23-43:1, and accordingly baseloaded units tend to have high utilization factors. As the chart above shows, the Armstrong, Hatfield's Ferry and Mitchell 3 units all had high utilization factors ranging from 90 percent for Armstrong 1 to 69 percent for Mitchell 3: most of the time these units were available, Allegheny was operating them to generate electricity.

[55] The source for the reserve shutdown data in this column is DTX 1399 at .0020-.0025 (Armstrong 1), DTX 1399 at .0043-.0046 (Armstrong 2), DTX 1399 at .0079-.0080 (Hatfield's Ferry 1), DTX 1399 at .0112-.0115 (Hatfield's Ferry 2, Oct. 1990 – Sept. 1992), DTX 1399 at .0121-.0123 (Hatfield's Ferry 2, Feb. 1997 – Jan. 1999), DTX 1399 at .0156-.0159 (Hatfield's Ferry 3), DTX 1399 at .0120-.0213 (Mitchell 3).

[56] Sources for the availability figures are: PTX 1969 (Armstrong 1); PTX 1977 (Armstrong 2); PTX 1985 (Hatfield's Ferry 1); PTX 1993 (Hatfield's Ferry 2, Oct. 1990 – Sept. 1992); PTX 1997 (Hatfield's Ferry 2, Feb. 1997 - Jan. 1999); PTX 2005 (Hatfield's Ferry 3); PTX 2009 (Mitchell 3).

Finally, Mr. Koppe testified that the units were baseloaded in the 1990s. T.T., Sept. 14, 2010, at 202:22-203:1; *see also* T.T., Sept. 20, 2010, at 11:3-16 (repeating his conclusion for the Hatfield's Ferry units). With regard to the Hatfield's Ferry units, Allegheny employee Dale Evans also testified that they were baseloaded in the 1990s. T.T., Sept. 23, 2010, at 136:14-17. Accordingly, because Allegheny ran the units as baseloaded units, the presumption under *Cinergy* that increases in availability result in increases in generation applies here.

This relationship between increased availability and increased generation for baseloaded units is simple common sense. When these units were available, Allegheny usually used them, so if they became more available, Allegheny was very likely to use them during the additional hours of availability. If Allegheny operates a baseloaded generating unit 80 percent of the time that it is available – i.e., the unit has a utilization factor of 80 percent – and Allegheny anticipates that the unit will be available 100 hours more next year, it is reasonable to anticipate that Allegheny will use the unit for approximately 80 of those additional 100 hours, consistent with its past practice.

Allegheny's itself expected increases in availability to translate into increases in generation, as expressed in the economic analyses it performs for large capital like the PSD Projects. For example, for the three Hatfield's Ferry lower slope PSD Projects in this case, Allegheny calculated that the expected availability increase of 768 hours would cause a generation increase of 302,630,400 kilowatt hours. PTX 633 at R-3 02096 (calculating availability gain as "8 OUT/YR X 4 DAY/YR [*sic*] x 24 HR/DAY"); *id.* (calculating generation increases as "8 OUT/YR X 4 DAY/YR [*sic*] x 24 HR/DAY x .710 x 555 MW x 1000KW/MW"). In that analysis, Allegheny calculated the increased availability and generation it expected from the project. PTX 715 at AE_DUN_00194044 (calculating availability gain as "3 Outages/Year x

3 Days/Outage x 24 Hours/Day"); *id.* (calculating generation increases as "3 Outages/Year x 3 Days/Outage x 24 Hours/Day" x .743 x 555 MW x 1000 KW/MW = 89,070,040 Kwhr/Yr").

Dr. Rosen confirmed that increased availability would likely produce increased usage of the units and increased electrical generation. He used a standard statistical approach, regression analysis, which attempts to fit a straight line to data. T.T., Sept. 21, 2010, at 68:19-71:24; PTX 2151 (d). That analysis showed a strong, linear relationship between unit availability and unit capacity factor at the Armstrong, Hatfield's Ferry and Mitchell 3 units: as unit availability increased, unit capacity factor – representing the amount of time the unit was generating electricity -- usually increased as well. *Id.* Based on Dr. Rosen's statistical analysis, Mr. Graves acknowledged that the relationship is "fairly steady," T.T., Sept. 22, 2010, at 51:16-20, and did not dispute Dr. Rosen's conclusion that the statistical analysis shows, to a "very high probability," that increases in availability at a unit have led to an increase in the amount of electricity generated at the unit, T.T., Sept. 21, 2010, at 70:17-71:13 (Dr. Rosen). Plaintiffs do not have to prove their case with absolute certainty, and proving this premise "to a very high probability" more than satisfies their burden of proof.

e. Dr. Rosen Did Not Err in Excluding the Purported Heat Rate Improvement at Armstrong from His PSD Emissions Projections

Allegheny argues that it expected no increase in annual emissions from the Armstrong PSD Projects because it expected that the work in the 1994 and 1995 outages would improve the efficiency, or heat rate, of the Armstrong units, and further expected that the emissions reductions from the efficiency improvement would have more than offset any emissions increases from improved availability. *See*, *e.g.*, T.T., Sept. 22, 2010, at 107:8-21 (comments of Allegheny's counsel). The law and facts, however, do not support Allegheny's argument.

As noted in Argument section IV.C.3.c.ii above, the only evidence at trial, from Mr. Koppe, indicated that there was no reason to expect a decrease in emissions due to any heat rate effects from the Armstrong PSD Projects. The 1993 Mooney memorandum assumed that the anticipated improvement in heat rate would *decrease* emissions, due to the use of less coal per unit of electricity generated. But Mr. Mooney failed to consider the two things Mr. Koppe examined. First, Mr. Mooney never separated out the work on the PSD Project, the "back end" work that Allegheny referred to as the "Boiler Project," from the other work being done during those outages, and thus never recognized that the "back end" work would not have affected the heat rate. Second, Mr. Mooney never considered whether the improved heat rate would also tend to *increase* emissions because the unit became less expensive to run and therefore would have run more. Because he failed to consider these issues, his analysis does not contradict Mr. Koppe's conclusion that the PSD Projects would not affect efficiency, and the evidence supports Dr. Rosen's decision to exclude the effect of any anticipated heat rate improvements from his Armstrong PSD calculations.

f. Allegheny Has Established No Basis for Netting

Allegheny argues that Dr. Rosen's methodology is inconsistent with the PSD regulations because he failed to perform a netting calculation. T.T., Sept. 22, 2010, at 4:13-5:10 (comments of Allegheny counsel). But as shown above, neither the purported reductions in utilization from PURPA imports, load modification or the installation of the Harrison scrubbers, nor the purported reductions in emissions from the low-NO_x burners, qualified for netting, so there was in fact no reason to perform any netting calculations. *See* Argument sections IV.C.3.c.ii and IV.D.1.c above.

g. The Methodology Dr. Rosen Used Does Not Always Produce an Emissions Increase

In a morning conference with counsel, the Court queried whether Dr. Rosen's methodology always produces an emissions increase. T.T., Sept. 22, 2010, at 7:25-8:13. The evidence shows that is not the case. As Allegheny's expert Mr. Graves testified, depending on the assumptions Dr. Rosen makes for the input values, the five-equation methodology can calculate increases or decreases. T.T., Sept. 22, 2010, at 80:15-21. As Mr. Graves agreed, if Dr. Rosen assumed a 0.81 percent increase in availability, and a 2 percent decrease in sulfur content, his methodology would show an SO_2 emissions decrease of approximately 1.2 percent. T.T., Sept. 22, 2010, at 79:20-80:14.

It is not even true that Dr. Rosen predicted emissions increases for every project in plaintiffs' complaint. As noted earlier, for the Hatfield's Ferry 2 secondary superheater outlet header project, Dr. Rosen did not find any emissions increase because Mr. Koppe did not find an expected availability improvement from that project. T.T., Sept. 21, 2010, at 64:20-65:12.

Thus, the simple fact that Dr. Rosen's calculations showed an emissions increase for every PSD Project at issue *at trial* does not prove that the methodology always produces emissions increases. As explained in Argument section IV.D.1.b.i above, plaintiffs have dropped claims regarding projects, like the Hatfield 2 secondary superheater project, for which Dr. Rosen's calculations did not show emissions increases. It follows that all of the projects at trial would show emissions increases.

Finally, Dr. Rosen would have predicted some emissions decreases in this case if the law had allowed Allegheny to take credit for the NO_x emissions reductions from the installation of the low-NO_x burners. As noted in Argument section IV.C.3.c.ii above, Dr. Rosen held the NO_x emissions factors constant because the law did not allow Allegheny to take credit for those NO_x

reductions. Had the law allowed Allegheny to take credit, he would have in some cases calculated emissions decreases. For example, for the Armstrong 1 PSD Project, if Dr. Rosen had used the high-NO_x emissions factor in the pre-project period, and the low-NO_x emissions factor for the post-project estimate, he would have calculated a 2,766 ton per year *decrease* in NO_x emissions. *See* PTX 2178 (high-NO_x pre-project baseline emissions amount of 4,973 tons for Armstrong 1); PTX 2179 (low-NO_x post-project emissions projection of 2,207 tons for Armstrong 1). Thus, the legal requirements, not the technical *methodology*, determined whether he projected NO_x emissions increases for some projects.

h. Actual Post-Project Results Are Not an Accurate Measure of the Reliability of Dr. Rosen's Methodology

Allegheny presented evidence at trial indicating that Dr. Rosen's emissions projections did not match the actual emissions outcomes. Courts do not rely on post-project emissions in new source review cases. *See United States v. Cinergy Corp.*, No. 99-cv-1693, Order at 2 (March 20, 2008) [PTX 2215 (d)] (excluding all evidence of post-project results); *Ohio Edison*, 276 F. Supp. 2d at 883 (noting that the court was not relying on post-project emissions figures but observing in passing that, consistent with Dr. Rosen's projections, in many cases the project actually resulted in emissions increases).

Such evidence is legally irrelevant, even with respect to evaluating the reliability of PSD emissions calculations, for at least two reasons. First, the PSD regulations exclude certain anticipated changes in factors that may influence the actual post-project results. As a result, PSD emissions projections are not designed to forecast the actual results, and the PSD projections may be higher or lower than the actual results because of influences that are expected to occur but cannot be included in PSD calculations. Second, aside from the constraints of the PSD

regulations, projecting future emissions is not an exact science: unanticipated events and causes can make actual post-project results differ from even the best predictions.

i. Actual Post-Project Figures Are Not a Standard for Evaluating the Reliability of PSD Emissions Projections Because the PSD Regulations Exclude the Influence of Factors That Affect Actual Emissions Results

Because the PSD regulations contain a number of provisions that exclude factors from PSD emissions calculations or limit their effect, PSD emissions projections are unlikely to match actual post-project emissions amounts. As explained above, in stage one of the PSD calculations, there is the limitation to the effects of the "physical change" or project and the demand growth exclusion, and in stage two, there are the netting limitations. Those limitations make sense, since the purpose of the PSD program is to evaluate the effect of a particular "physical change" or project on emissions, not the effect of factors independent of the project that may be going on at the plant. Indeed, if PSD emissions calculations took into account the effect of all the factors independent of the projects, one could forecast a PSD emissions increase even when the project itself was not expected to increase emissions.

The effect of the limitations embodied in the PSD regulations is to exclude factors that would be expected to influence the actual emissions outcome, and, as a result the PSD projection is unlikely to match the actual emissions By way of analogy, there is a distinction between an individual's *actual* income and her *taxable* income, and actual income can vary significantly from taxable income. For example, a woman could anticipate and in fact receive a small raise in her salary, so that her *actual* income would be higher. But if she also buys a house for the first time, the mortgage deduction might be large enough to cause her *taxable* income to fall even while her actual income rises.

The PSD regulations operate in the same way: they exclude from emissions projections factors that may in fact play a role in the actual outcome. As a result, the actual outcome is not an accurate measuring stick for evaluating the merits of a projection. Instead, to evaluate the reliability of a PSD projection, one needs to evaluate the specific input values used and determine whether those input values properly reflect both the legal constraints and the factual information available before the project.

Dr. Rosen's treatment of low-NO_x burners under the netting rules illustrates this point. Dr. Rosen excluded the effect of low-NO_x burners from his calculations because he understood, from counsel, that the netting provisions of the PSD regulations did not allow Allegheny to receive credit in the PSD calculations for the anticipated emissions reductions from the burners. Under that legal assumption, he calculated emissions increases; if he had used different legal assumptions, he would have calculated NO_x emissions decreases for some projects. So the PSD legal requirements caused Dr. Rosen to make different projections than he would have if he were making projections for other, more general purposes, and the legal exclusion virtually guaranteed that his projection would be different than the actual result.

The same is true for the purported reductions in utilization from increased use of Harrison after installation of the scrubbers for Title IV, the PURPA imports and the load management activities, and the reductions in coal sulfur content for Title IV. Had Dr. Rosen included anticipated reductions in utilization in his calculations, his projections would have been lower, and might even have shown emissions reductions, depending on how large a utilization reduction he would have included. But as shown in Argument sections IV.D.1.c above, the regulations do not allow the inclusion of the purportedly anticipated reductions in utilization, and

in any event, Allegheny did not provide any evidence showing that such anticipated reductions, if any, were large enough to have a material effect on Dr. Rosen's calculations.

In addition, the demand growth exclusion removes certain anticipated increases in emissions from PSD projections, but these anticipated increases might actually occur and contribute to actual post-project emissions. Thus, applying the exclusion can cause PSD emissions projections to be lower than actual emissions.

In sum, then, EPA did not design the PSD regulations to perform a general evaluation of future emissions at a generating unit. Instead, it designed the regulations to isolate the influence on emissions of one factor: the project at issue. To accomplish that end, the regulations exclude the effect of many other factors that are unrelated to that project, and only give credit for such unrelated emissions changes to the extent they are voluntary (*i.e.* surplus), quantifiable, locked-in (*i.e.*, permanent) and federally enforceable changes that meet the netting requirements. Thus, because the PSD projections intentionally do not look at the effect of all events, activities or factors that influence future emissions, the PSD projections are unlikely to match the actual future emissions amounts.

ii. Power Plant Emissions Are to a Certain Extent Unpredictable

"Predictions are hard to make, particularly if they involve the future." *Ohio Edison,* 276 F. Supp. 2d at 880. This conclusion – attributed to both Yankees catcher Yogi Berra and Nobel Prize-winning physicist Niels Bohr [57] – applies to projecting future emissions from power plants. As Dr. Rosen indicated, emissions from a coal-fired generating unit are subject to several influences – the unit's availability, the extent to which one uses the unit when it is available, the

[57] *See*, *e.g.*, "Yogi Berra," *at* http://en.wikiquote.org/wiki/Yogi_Berra; "Niels Bohr," *at* http://en.wikiquote.org/wiki/Niels_Bohr.

unit capacity, the unit heat rate, the heat content of the coal, and the emissions factor, including the sulfur content of the coal. Those factors can vary randomly independent of any particular project or intentional strategy. For example, in 1994 at Hatfield's Ferry 1, the monthly coal heat content varied from 12,603 to 12,947 BTU/lb. PTX 1156 at DOE_EIA001332.

Because unforeseen changes can and do occur, actual post-project figures are a poor basis for evaluating projections because they fail to adjust for those unforeseen changes. As Mr. Graves agreed, even if one makes the best possible assumption about the future value of a certain factor, it can turn out to be different than what actually happens because of unforeseen events. T.T., Sept. 22, 2010, at 73:10-74:4.

As it turns out, however, Dr. Rosen's projections were actually more accurate than some emissions projections that Allegheny itself made. In 1995, Allegheny reviewed two sets of its own aggregate NO_x emission projections from the Armstrong, Hatfield's Ferry, Mitchell 3 and R. Paul Smith power stations[58]. PTX 1871 at AE_MIT00038651, AE_MIT00038652. Some of the forecasts came relatively close to the projections, others did not. For one set of forecasts, the projected amounts always exceeded the actual results. *Id.* at AE_MIT00038651.

In percentage terms, the largest difference between Allegheny's projections and the actual results was 18 percent, in the 1991 figures on the second set of forecasts. *Id.* at AE_MIT00038652 (difference between 1991 projection of 12,318 tons and actual result of 15,022 tons, divided by actual result of 15,022 tons). Dr. Rosen did better, however. If one aggregates Dr. Rosen's results for Armstrong, Hatfield's Ferry and Mitchell 3 as Allegheny did, the difference between his projections and the actual results was much smaller: 3.2 percent for

[58] The Smith plant is a small generating unit located in western Maryland. PTX 20 at 13.

SO_2, and 10.5 percent for NO_x (using the low-NO_x assumption). *See* Plaintiffs' Finding of Fact 737, 738.

Thus, for all of Allegheny's complaining about Dr. Rosen's methodology, his projections fall within the range of reliability of Allegheny's own ordinary-course-of-business projections. Since Allegheny's expert Mr. Graves did not perform emissions projections, there is no evidence that any other methodology would have produced results better than Dr. Rosen's. T.T., Sept. 22, 2010, at 67:8-25 (Mr. Graves).

To sum up, performing emissions projections does not allow for exact precision: no one – not Allegheny, not Mr. Graves, and not Dr. Rosen – can forecast emissions with 100 percent accuracy, whether for PSD purposes or for any other purpose. Making PSD emissions for a project requires (1) complying with the PSD regulations, (2) within those constraints, using a methodology that reflects the scientific and engineering principles governing power-plant operations, and (3) making the best assumptions about availability and other relevant factors that one can based on the information available before the project. Dr. Rosen complied with those requirements in this case, and his calculations therefore show what reasonable PSD emissions projections would have shown if Allegheny had performed any.

2. The Hatfield's Ferry and Mitchell 3 Projects Were Not RMRR

Allegheny asserts that it is not liable for PSD violations for the Hatfield's Ferry and Mitchell PSD Projects because those projects are subject to a regulatory exception for "routine maintenance, repair or replacement," or RMRR.[59] 40 C.F.R. § 52.21(b)(2)(iii)(*a*) ("[a] physical change . . . shall not include: *(a)* Routine maintenance, repair and replacement"). Allegheny bears the burden of proof on this defense. Docket Item 220 at 14 (citing cases), *as adopted by*

59 Allegheny does not assert the RMRR defense for any projects at the Armstrong plant.

Docket Item 380. Allegheny's assertion of the RMRR defense fails as a matter of law and fact because it relies on an impermissibly expansive definition of the regulatory RMRR exclusion.

a. As a Matter of Law, the RMRR Exemption Is Limited to Trifling, De Minimis *Projects*

As a matter of law, the RMRR exemption cannot be given an expansive interpretation that would cover the Hatfield's Ferry and Mitchell PSD Projects. As explained in Argument section IV.B.1 above, the PSD statute creates no exceptions to the "physical change" component of PSD applicability. Nonetheless, when EPA promulgated the PSD regulations, it used its administrative authority to create the RMRR exception: "[a] physical change or change in the method of operation shall not include: (a) Routine maintenance, repair, and replacement." 40 C.F.R. § 52.21(b)(2)(iii)(*a*).

It is a basic principle of statutory interpretation that when a statute does not provide for an exemption, any such exemption created by regulation is narrowly construed. *See, e.g., O'Neal v. Barrow County Bd. of Comm'rs*, 980 F.2d 674, 677 (11th Cir. 1993). Consistent with that principle, "EPA has for over two decades defined the RMRR exclusion as limited to '*de minimis* circumstances.'" *New York v. EPA*, 443 F.3d 880, 884 (D.C. Cir. 2006) (quoting 68 Fed. Reg. 61248, 61272 (Oct. 27, 2003)).

On a couple of occasions, however, EPA has attempted to extend exclusions beyond *de minimis* limits, and each of those attempts has been struck down by the D.C. Circuit, the only court with jurisdiction over challenges to EPA's nationwide regulations, *see* 42 U.S.C. § 7607(b)(1); *United States v. Cinergy Corp.*, 458 F. 3d 705, 707-08 (7th Cir. 2006), *cert. denied*, 549 U.S. 1338 (2007). In *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), the D.C. Circuit struck down EPA regulations exempting sources that emitted less than fifty tons of pollutants per year. *Id.* at 355-56, 399-400. The court identified only two grounds on which

exemptions to a "clear command of a regulatory statute" might be based: administrative necessity and *de minimis* circumstances. *Id.* at 358, 357-61. Thus, while EPA had a limited ability to overlook "trifling matters," *id.*, that authority was not a license to "depart from the statute," but only "a tool to be used in implementing the legislative design." *Id.* at 360.

In 2003, EPA promulgated regulations expanding the RMRR exception beyond *de minimis* projects to include replacement of components that cost up to twenty percent of the generating unit's value. *See New York*, 443 F.3d at 883. Again, the D.C. Circuit rejected this expanded RMRR exception as contrary to the plain language of the Clean Air Act. "[b]ecause Congress used the word 'any,' EPA must apply [PSD requirements] whenever a source conducts an emissions increasing activity that fits within one of the ordinary meanings of 'physical change.'" 443 F.3d at 885. The court further explained:

> As Congress limited the broad meaning of "any physical change," directing that only changes that increase emissions will trigger [PSD requirements], no other limitation (other than to avoid absurd results) can be implied. *The definition of "modification," therefore, does not include only physical changes that are costly or major*.

Id. at 890 (emphasis added). The court reiterated that "the agency's inherent power to overlook 'trifling matters'" permits the agency "to diverge from the plain meaning of a statute only so far as is necessary to avoid its futile application." *Id.* (quoting *Alabama Power*).

Only one court has held that projects of more than a *de minimis* nature can qualify for the RMRR exemption. *National Parks Conservation Ass'n v. Tennessee Valley Auth.*, No. 3:01-cv-71, 2010 WL 1291335 (E.D. Tenn. Mar. 31, 2010). In that decision, the district court held that modifications to a power plant were RMRR even though those changes were substantial, cost millions of dollars, took nearly three months to perform, would extend the plant's life by decades, and were, in a nutshell, "not a small task." *Id.* at *25. That outlier ruling creates a

broad exclusion inconsistent with the Congressional command that PSD requirements apply to "any physical change" that increases emissions, and is currently on appeal.[60]

In sum, then, the RMRR exception is limited to *de minimis* activities. Docket Item 220 at 14, *as adopted by* Docket Item 380. In determining whether a project is a "trifling matter" subject to the RMRR exemption, this Court has followed other courts in adopting the four-factor *WEPCO* test. *Id.* at 6. Under that test, the courts engage in a case-by-case analysis, looking at the project's (1) nature and extent, (2) cost, (3) purpose and (4) frequency, to arrive at a "common sense" conclusion as to whether the project is RMRR. *New York*, 443 F.3d at 883-84; *accord* Docket Item 220 at 6, *as adopted by* Docket Item 380; *WEPCO*, 893 F.2d at 910; *United States v. Cinergy Corp*., 495 F. Supp. 2d 909, 930 (S.D. Ind. 2007); *Ohio Edison*, 276 F. Supp. 2d at 856. Under the *WEPCO* test, no single factor is dispositive. Docket Item 220 at 6, *as adopted by* Docket Item 380; *see also Sierra Club v. Morgan*, No. 07-C-251-S, 2007 WL 3287850 at *12 (W.D. Wis. Nov. 7, 2007).

As far as benchmarks for applying this four-factor *de minimis* standard, this Court has already ruled that: "[r]outine maintenance, repair and replacement occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by in house employees, and is treated for accounting purposes as an expense." Docket Item 220 at 14 (quoting *United States v. Ohio Edison Co*., 276 F. Supp. 2d 829, 834 (S.D. Oh. 2003)), *as adopted by* Docket Item 380. "In contrast, 'capital improvements generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes

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[60] The Sixth Circuit has already reversed an earlier decision from the *TVA* court on statute-of-limitations issues. *National Parks Conservation Ass'n v. Tennessee Valley Auth.*, 480 F.3d 410 (6th Cir. 2007).

as capital expenditures on the balance sheet." *Id.* Those benchmarks are consistent with EPA's interpretation of the *WEPCO* RMRR test, since at least 1989, to "include only those [activities] that (1) are frequently done at that plant, (2) involve no major equipment, (3) are inexpensive, and (4) do not extend the life of the plant." PTX 179 at UARG1 0000095 (1989 admission of the Utility Air Regulatory Group, or UARG).

These benchmarks are consistent with Allegheny's own common-sense understanding of routine maintenance in the 1990s. Allegheny's employees did not use the term "routine maintenance" to describe large-scale undertakings like the PSD Projects. In 1994, for example, an Allegheny employee, Terry Misner, testified that "[Allegheny has] an extensive program to perform both *routine maintenance* and more complex major maintenance projects." PTX 157 at AE_DUN_00721437 (emphasis added). In 1992 testimony, senior Allegheny executive Donald Feenstra also distinguished between "routine maintenance" performed by in-house staff, and other more extensive work performed by outside contractors. PTX 156 at 482452, lines 4-8. At deposition, the supervisor of an Allegheny "maintenance crew" testified that: "[t]ypically routine maintenance can be done on redundant equipment or equipment that could be shut down temporarily" without taking the whole unit offline. D.T. (Jeff Mooney Aug. 22, 2007) at 20:3-21:3. Allegheny's manager of asset accounting testified at deposition that "[r]outine maintenance would be, I need to go in and clean out this valve or I need to lubricate this part, those types of things." D.T. (Dennis Herron 30(b)(6) Aug. 15, 2007) at 56:24-57:2.

Allegheny's view is consistent with the testimony of plaintiffs' expert Mr. Koppe, who distinguished between routine maintenance activities, such as taking an oil sample, calibrating equipment or replacing a two-foot length of one boiler tube, and fundamentally different non-routine projects that involve the replacement of entire components weighing hundreds of

thousands of pounds. T.T., Sept. 20, 2010, at 59:11-60:7; *see also*. T.T., Sept. 14, 2010, at 216:19-22, 217:6-8; T.T., Sept. 20, 2010, at 16:4-9.

b. The Hatfield's Ferry and Mitchell PSD Projects Were Not RMRR Because They Were Not Trifling, De Minimis *Activities*

None of the massive, complex Hatfield's Ferry or Mitchell 3 PSD Projects were trifling, *de minimis* projects subject to the RMRR exclusion under the four-factor *WEPCO* test. To the contrary, each of the *WEPCO* factors – nature and extent, purpose, cost and frequency – supports a finding that the projects were not RMRR.

i. The Nature and Extent of the Projects Was Not Consistent with RMRR

Under the nature and extent prong of the RMRR test, courts have consistently held that extensive replacements, advanced planning, design upgrades, use of improved materials, use of outside contractors and the installation of structures such as monorails or cranes to facilitate the work are facts that weigh strongly against finding that a given project was RMRR. *See Cinergy*, 495 F. Supp. 2d at 944 (fact that slope tube project was performed by outside contractors, involved a new configuration and took 11 weeks, "strongly support[s] a conclusion that the project was not routine"); *id.* at 938 (use of outside contractors to install custom-built tubes suggested that reheater project was not routine); *id.* at 940-41 (extensive planning, over two month long outage and use of outside contractors showed that the project was not routine); *id.* at 943 (monorail suggested project was not routine); *Sierra Club v. Morgan*, No. 07-C-251-S, 2007 WL 3287850, at *14 (W.D. Wis. Nov. 7, 2007) (replacement of 100 percent of component, use of outside contractors, 37 to 81 day length of projects, and need to bring in a crane to perform the projects indicated that projects were not RMRR); *id.* at *16 (use of materials fabricated off-site suggested that project was not RMRR); *Ohio Edison*, 276 F. Supp. 2d at 858-60 (size and

use of outside contractors were among factors showing the projects were not RMRR); *id.* at 834 (RMRR does not include "permanent improvements" and "is usually performed in large plants by in house employees").

As shown below, these factors – extensive replacements, advanced planning, design upgrades, use of improved materials, use of outside contractors and the installation of structures such as monorails or cranes to facilitate the work – characterize the Hatfield's Ferry and Mitchell PSD Projects and therefore favor a finding that the purpose and nature of those projects are not consistent with RMRR. *See, e.g.*, Docket Item 220 at 16 (stating that the nature and extent of the 1999 Hatfield's Ferry 2 lower slope project did not appear to be consistent with the RMRR exception), *as adopted by* Docket Item 380.

Hatfield's Ferry Lower Slope Projects: Allegheny began planning for these projects no later than February 1995. *See* Docket Item 430 ¶ 26; PTX 181 (February 1995 capital work order for lower slope project at Hatfield's Ferry 2). That was approximately 18 months before the project was performed at unit 3 in fall 1996, approximately 2 ½ years before the project was performed at unit 1 in fall 1997, and approximately 4 ½ years before the project was performed at unit 2 in fall 1999. Docket Item 430 ¶¶ 27, 49, 57. The three projects each involved removing the existing lower slope panels, inlet headers, seal skirt and ash hopper, and replacing those items in their entirety with newly fabricated materials that Allegheny variously described as involving "an improved design," "an upgraded design" and "a redesign of the lower furnace area in order to take advantage of improvements such as: thicker tubing to address slope erosion and corrosion problems, an improved structural support system to better resist damage from slag falls, improved materials and configuration of the furnace seals to provide a longer service life, and upgraded ash hoppers to improve ash handling capabilities." PTX 183 at R-3 02085

(memorandum explaining that alternative "piece-meal" approach had been rejected); PTX 633 at R-3 02089 (illustrating improvement in design); PTX 186 at AE_DUN_00131796; PTX 184 at 00131831 ("Project Overview"); PTX 185 at AE_DUN_00131793 (capital expenditure authorization request); PTX 194 at AE_HQ_00068239-40 (post-outage summary of the work). The slope tube panels alone are large, each about 60 feet wide. *See* Docket Item 166 ¶ 27. Each new slope panel included 464 tubes, and the slope panels were just one part of the projects. *See* PTX 187 at AE_DUN_00131869-76.

Allegheny hired outside vendors to fabricate the new materials and outside contractors to do the demolition, removal and installation work for the projects — none of those activities were performed by Allegheny's Hatfield's Ferry maintenance staff. PTX 187 at AE_DUN_00131868 – AE_DUN_00131869 (specification identifying materials to be fabricated and furnished by outside contractor); PTX 190 (memorandum requesting approval of purchase orders to Minnotte Corporation "for the fabrication of materials required for the 1999 Unit 2 Hatfield boiler outage"); PTX 191 (purchase order issued to Minnotte for the materials); PTX 184 at AE_DUN_00131828 (estimating costs for the mechanical, insulation and electrical contractors).

Finally, the Hatfield's Ferry lower slope projects required 10- to 12-week outages to perform, plus additional pre-outage time building a platform and a monorail to allow for the new materials to be installed. *See, e.g.*, Docket Item 430 ¶¶ 27, 49, 57; PTX 194 at AE_HF00068242 – AE_HF00068258 (summarizing the work performed before and during the outage).

Hatfield's Ferry 2 Fall 1993 Pendant Reheater Project. Allegheny began planning for this project at least 18 months before undertaking it. Docket Item 430 ¶ 40. The project involved removing the existing pendant reheater and crossover tubes and replacing them with newly fabricated assemblies made out of a higher-grade steel that was stronger and much more

resistant to corrosion. *Id.* ¶ 42; T.T., Sept. 20, 2010, at 18:16-19:4; PTX 715 at AE_DUN_00194034, AE_DUN_00194036. Because of the upgraded steel, Allegheny expected the new pendant reheater to have a 30-year effective life. PTX 715 at AE_DUN_00194037.

The pendant reheater was so large that it would not fit in the courtroom: it consisted of 125 pendants, each of which was 40 feet high and 20 feet from front to back, and in total contained about 17 miles of tubing. T.T., Sept. 20, 2010, at 13:6-14:1; *see Cinergy*, 495 F. Supp. 2d at 937 (replacing 65 reheater pendants was not RMRR). Each pendant weighed several thousand pounds. T.T., Sept. 20, 2010, at 22:1-2. Allegheny hired outside vendors to fabricate the new materials and outside contractors to do the demolition, removal and installation work because the project was too extensive for in-house maintenance staff. T.T., Sept. 20, 2010, at 23:11-21. The contractors would have had to install a crane or monorail to remove the old pendants and install the new ones. *Id.* at 22:5-6, 22:8-15, 22:21-24. The new pendants were delivered by truck in approximately 400-500 large pieces that had to be assembled on site before being installed. *Id.* at 22:24-23:4.

Finally, the Hatfield's Ferry 2 pendant reheater project required a 10-week outage to perform, including 8 ½ weeks of actual work on the removal of the old reheater and installation of the new one. *See, e.g.*, Docket Item 430 ¶¶ 27, 49, 57; T.T., Sept. 20, 2010, at 24:17-23. Two shifts of approximately 40 people worked six days a week to complete the project. T.T., Sept. 20, 2010, at 23:22-24:7.

Hatfield's Ferry 1 Fall 1997 Secondary Superheater Outlet Header Project. Allegheny began planning for this project over two years before undertaking it. Docket Item 430 ¶ 34. The project involved removing both secondary superheater outlet headers at the unit and replacing them with newly fabricated headers that were of an upgraded design and stronger material than

original headers. *Id.* ¶ 35; T.T., Sept. 20, 2010, at 18:16-19:4; PTX 715 at AE_DUN_00194034, AE_DUN_00194036. Allegheny expected the new pendant reheater to have at least a 30-year effective life. T.T., Sept. 20, 2010, at 29:4-9.

The headers were about 60 feet long – so long that they might not fit in the courtroom – and contained about 17 miles of tubes. T.T., Sept. 20, 2010, at 13:3-14:1. Together, the old headers weighed about 90,000 pounds (45 tons) each, while the new headers weighed about 40,000 pounds (20 tons) each. PTX 758 at AE_MIT00033387.

Allegheny hired outside vendors to fabricate the new materials and outside contractors to do the demolition, removal and installation work — the project was too extensive for Allegheny's maintenance staff. T.T., Sept. 20, 2010, at 36:24-37:2; PTX 751 at AE_DUN_00005316, AE_DUN_0005319. A special crane was brought in to remove the old headers and install the new ones. PTX 751 at AE_DUN_00005322. The new headers were each lifted into place in two pieces which were then welded together. PTX 758 at AE_MIT00033388 – 389. The project required a 10-week outage to perform. *See, e.g.*, Docket Item 430 ¶¶ 33; T.T., Sept. 20, 2010, at 24:17-23.

Mitchell 3 Fall 1994 Lower Slope Panel Project. Allegheny began considering the work done on this project no later than December 1993, PTX 885 (letter providing information about "wear bars" to be install on lower slope panels), approximately 10 months before undertaking the project in October 1994, Docket Item 430 ¶ 67. This lower slope project at Mitchell 3 was similar to, although not as extensive, as the lower slope projects at the Hatfield's Ferry units. T.T., Sept. 20, 2010, at 52:20-53:5. The Mitchell project involved removing and replacing a substantial portion of the lower slope panels – 24 such panels, including 556 tubes – and replacing the removed portions with tubes coated with additional metal to better protect them

from falling ash. T.T., Sept. 20, 2010, at 52:20-53:2, 55:16-25; PTX 293 at AE_DUN_191934; PTX 712 at AE_MIT00032304. Allegheny hired outside vendors to fabricate the new materials and outside contractors to do the demolition, removal and installation work for the project. T.T., Sept. 20, 2010, at 56:9-12 (materials to be furnished by one company and installed by another); PTX 293 at AE_DUN_00191934 (materials to be furnished by ABB/CE, labor to be provided by "plant mechanical contractor"); PTX 712 at AE_MIT00032304 (specifications for outside bidders on removal and installation work). The project required approximately five weeks to perform. T.T., Sept. 20, 2010, at 56:13-17.

ii. The Purposes of the Projects Are Not Consistent with RMRR

On the purpose prong of the RMRR test, courts have repeatedly held that performing a project for the purpose of reducing forced outages, and thereby improving availability and reliability, supports a finding that a given project was not RMRR. *See Cinergy*, 495 F. Supp. 2d at 938 (where purpose was to reduce leaks and forced outages and save the company money, that suggested the replacements were not routine); *id.* at 938, 941-46 (similar conclusion for several other projects); *Sierra Club*, 2007 WL 3287850, at *13 (project undertaken to "increase the availability and reliability of Boiler 4" and "made necessary due to the numerous tube failures" was "beyond mere maintenance" and "does not support that it was RMRR"); *id.* at *14-*17 (similar conclusion for three other projects); *Ohio Edison*, 276 F. Supp. 2d at 860-61 (where purpose "was to extend the lives of the units and make them available and reliable well into the future," that weighed against a finding that the projects were RMRR).

Under this authority, the purpose of the Hatfield's Ferry and Mitchell PSD Projects favors a finding that they are not RMRR. As noted in Argument section IV.C.3.b above,

Allegheny expected that outages would be reduced and availability would improve as a result of each of the component replacement projects at issue in this case.

iii. The Projects' Costs Are Not Consistent with RMRR

Courts have repeatedly held that when a project costs in the range of hundreds of thousands to millions of dollars, and is treated as a capital expenditure rather than a maintenance expense, it is not RMRR. *See Cinergy*, 495 F. Supp. 2d at 939 (on summary judgment, finding that reheater project was "not routine" when it cost $1,491,000 and was treated as a capital expenditure); *id* (on summary judgment, lower slope tube replacement project "was not routine" when it cost $2,145,000 and was treated as a capital expenditure); *id*. at 942-47 (same conclusion for other projects that were capitalized and that ranged in cost from $856,000 to $4,512,000). *Sierra Club*, 2007 WL 3287850, at *14-*17 (among others, projects costing $788,899 and $1,712,348 and treated as capital expenditures were not RMRR); *Ohio Edison*, 276 F. Supp. 2d at 859-60 (treatment of the projects as capital expenditures suggested they were not RMRR); *id.* at 834 (RMRR is "typically limited in expense"); *id.* at 861-62 (cost of $1,146,422 and treatment as capital expenditure supported finding that project was not RMRR).

Under that authority, as shown below, the large costs and capitalization of the Hatfield's Ferry and Mitchell PSD Projects indicates that they are not RMRR:

Hatfield's Ferry Lower Slope Projects. The three projects cost $5,918,077, $6,342,917 and $5,181,000. Docket Item 430 ¶¶ 31, 54; T.T., Sept. 20, 2010, at 52:3-5. That is at least 2.4 times the cost of the lower slope project determined, on summary judgment, not to be RMRR in *Cinergy*. 495 F. Supp. 2d at 939 ($2,145,000). By way of comparison, in 1995 Allegheny estimated that the "annual maintenance costs" for this area of the boiler were $130,000. Thus, the cost of each project was approximately 40 times the normal annual maintenance costs for the

area of the boiler covered by the project. *See Cinergy*, 495 F. Supp. 2d at 946, 947 (project not RMRR when it cost over $3,000,000 and utility had been spending $50,000-$90,000 per year to repair or shield tubing in that area). In addition, Allegheny treated the cost of these projects as a capital expenditure, not as a maintenance expense. T.T., Sept. 14, 2010, at 25:5-26:15; PTX 897.

Hatfield's Ferry 2 Pendant Reheater Project. The project cost $5,692,777. Docket Item 430 ¶ 44. That is 3.8 times the cost of the reheater project determined, on summary judgment, to be not RMRR in *Cinergy*. 495 F. Supp. 2d at 939 ($1,491,000). Allegheny estimated the annual maintenance costs for the pendant reheater area at that unit at $42,000. PTX 715 at AE_DUN_00194035. Thus, the cost of the project was over 135 times the annual maintenance costs for that area of the boiler. In addition, Allegheny treated the cost of the projects as a capital expenditure, not as a maintenance expense. T.T., Sept. 14, 2010, at 25:5-26:15; PTX 897.

Hatfield's Ferry 1 Secondary Superheater Outlet Header Project. The project cost $2,513,016. Docket Item 430 ¶ 37. That multi-million dollar cost exceeds the cost of many of the projects determined not to be RMRR in the case law cited above. Allegheny estimated the future cost of inspecting the outlet headers, if not replaced, as between $25,367 and $179,228 per year. PTX 214 at R-3 02955. Thus, taking the most conservative of those annual estimates, the cost of the project was over 14 times the expected future maintenance costs for that area of the boiler. In addition, Allegheny treated the cost of the project as a capital expenditure, not as a maintenance expense. T.T., Sept. 14, 2010, at 25:5-26:15; PTX 897.

Mitchell 3 Lower Slope Project. The project cost $626,402. Docket Item 430 ¶ 69. While less than the cost of the other lower slope projects in this case, that cost is comparable to

projects found not to be RMRR by other courts. *See Sierra Club*, 2007 WL 3287850 at *14-*17 (project costing $788,899 was not RMRR); *Cinergy*, 495 F. Supp. 2d at 942-43 (project costing $856,000 was not RMRR). In addition, Allegheny treated the cost of this project as a capital expenditure, not as a maintenance expense. T.T., Sept. 14, 2010, at 25:5-26:15; PTX 897.

iv. The Frequency of the Projects is Not Consistent with RMRR

Some courts, such as this Court, *see* Docket Item 380 at 14, consider both how frequently the project was done at the generating unit at issue as well as how frequently the same type of project was done at other plants in the electric utility industry. The latter "frequency in the industry" consideration is not, however, determinative or even a primary factor, because relying principally on frequency in the industry would eviscerate the PSD regulation: "[h]ow often similar projects are undertaken throughout industry may inform the analysis, but Congress certainly did not intend for companies to make an 'end run' on [PSD and nonattainment NSR] by allowing the routine maintenance exception to swallow the modification rule." *SIGECO*, 245 F. Supp. 2d at 1009; *see also WEPCO*, 893 F.2d at 911-912 (basing its finding that project was not RMRR on both the frequency at the particular units and frequency in the industry); *Ohio Edison*, 276 F. Supp. 2d at 856 ("It is the frequency of an activity at a particular unit that is most instructive in the analysis of what can be considered 'routine.' The types of activities undertaken within the industry as a whole have little bearing on the issue if an activity is performed at a unit only once or twice in the lifetime of that particular unit"); *SIGECO*, 245 F. Supp. 2d at 1016 ("WEPCO supports the view that the frequency of the project at the particular unit and the frequency of the project within industry are *both* relevant considerations") (emphasis in original). The case law is consistent with EPA's 1988 guidance, which explains the importance of frequency at the unit: among "[t]he most important factors" that support a finding

that a project is not RMRR is that "the renovation work items . . . are those that would normally occur only once or twice during a unit's expected life cycle." PTX 172 at EPAOAQ 0053039 – 040.

Thus, the case law provides that if a project is typically done only once or few times in the life of a generating unit, that favors a finding that the project is not RMRR. *See Sierra Club*, 2007 WL 3287850 at *14 (project 2 was not RMRR because the tubes had "never been worked on as one project" and such a project "is expected to occur only 2 maybe 3 times in the life of a boiler"); *id.* at *15 (although the project 3 economizers had been replaced in their entirety once before, such replacements were expected to occur only every 24 years and "[s]uch infrequent replacement can hardly be considered routine."); *id.* at *15 (although the project 4 feeders had been replaced once before and had been replaced at other units also, the project was not RMRR because it involved a "new design," not mere replacement); *id.* at *17 ("Although some of the replaced components . . . had been previously replaced, none had been replaced more than twice and several were never replaced before. . . . such minimal frequency weighs against Project 5 having been RMRR."); *Cinergy*, 495 F. Supp. 2d at 938-39 (ruling on summary judgment that frequency factor weighed against RMRR where all of the tubes had never previously been replaced in a single outage and where there was no evidence that such projects were "regularly done" either at the unit or in the industry); *id.* at 946 (similar conclusion on summary judgment for a different project); *Ohio Edison*, 276 F. Supp. 2d at 861 (projects "considered once or twice in a unit's lifetime" were not routine).

Under this authority, the rarity of the Hatfield's Ferry and Mitchell PSD Project in the life of the generating units supports a finding that those projects were not RMRR:

Hatfield's Ferry 1, 2 and 3 Lower Slope Projects. Before these 1996, 1997 and 1999 projects, Allegheny had never before replaced the entire lower slopes at any of the Hatfield's Ferry units. T.T., Sept. 20, 2010, at 49:03-12; *see also* PTX 184 at AE_DUN_00131830 PTX 419 at R-2 00020 through R-2 00027). In addition, Allegheny assumed that it would not perform such an extensive replacement and redesign again any time soon for these lower slope tube projects since it assumed the improved lower slope structures would have a 25-year effective life. PTX 633 at R-3 02095.

Hatfield's Ferry 2 Pendant Reheater Project. Prior to this 1993 project, Allegheny had never before replaced the entire pendant reheater at this Hatfield's Ferry 2 in the 23 years the unit had been operating. T.T., Sept. 20, 2010, at 24: 8-11; Docket Item 430 ¶ 19. Allegheny assumed that it would not perform such an extensive replacement again any time soon since it expected that, because of the use of upgraded steel, the new reheater would have a 30-year effective life. PTX 715 at AE_DUN_00194036.

Hatfield's Ferry 1 Secondary Superheater Outlet Header Project. Prior to this 1997 project, Allegheny had not replaced the secondary superheater outlet headers at Hatfield's Ferry 1since the unit came on line 28 years earlier, in 1969. Docket Item 430 ¶¶ 18, 39. Allegheny assumed that it would not have to replace the new outlet headers for another 37 years. PTX 214 at R-3 02953 (assuming that the "action life" of the new outlet headers would be 37 years).

Mitchell 3 Lower Slope Project. Before the project, Allegheny had never before replaced this magnitude of lower slope tubes at the Mitchell 3 unit. T.T., Sept. 20, 2010, at 55:12-15. To plaintiffs' knowledge, Allegheny has not performed a lower slope project of the same magnitude on that unit in the 16 years since the project.

In the preceding discussion, plaintiffs have addressed the frequency of the projects at the particular generating unit. The Court has indicated that it will consider evidence of what was routine in the industry as well. Docket Item 220 at 13**,** *as adopted by* Docket Item 380. Allegheny provided no probative evidence on this point during discovery. *See* Docket Item 220 at 19 (on summary judgment, noting that Mr. Golden had relied on a summary of projects, but that no evidence showed the scope or duration of those projects), *as adopted by* Docket Item 380.

Over plaintiffs' objection, the Court allowed Allegheny to present new expert opinion at trial based on material Allegheny's expert obtained and reviewed after discovery closed. *See* Docket Item 394; Transcript of Pretrial Conference (Aug. 27, 2010), at 6:18-10:14. As explained below, Mr. Golden's post-discovery opinions based on that additional evidence are no more probative on the "routine in the industry" point than his earlier opinions that the Court already rejected.

For all of the above reasons, the Hatfield and Mitchell projects are not RMRR and not exempt from liability on plaintiffs' PSD claims.

c. Allegheny Did Not Meet Its Burden of Showing that the Hatfield's Ferry and Mitchell PSD Projects Were RMRR

Allegheny will attempt to prove its RMRR defense by relying on the testimony of its expert, Jerry Golden. That attempt should fail because Mr. Golden's efforts to apply the four-factor *WEPCO* test suffer from numerous flaws that render his opinions unreliable.

Nature and Extent. Mr. Golden looks at the "nature" and "extent" aspects separately, and neither of those analyses provide legitimate support for a conclusion that the PSD Projects were RMRR. His analysis of the "nature" aspect of the *WEPCO* test is biased in favor of finding projects to be RMRR because he only looks at the universe of large component replacement

projects. He testified that when performing such major projects, utilities typically improve designs and upgrade materials, perform a cost-benefit analysis, treat the projects as capital expenditures, perform the work during an outage, use outside contractors and use "rigging and handling" arrangements to move materials in and out of the boiler. T.T., Sept. 28, 2010, at 43:24-52:10. But this analysis essentially assumes the answer: Mr. Golden looks at a limited universe of the largest, most extensive projects, finds that the largest, most expensive projects are similar, and then concludes that the largest, most extensive projects are routine. Mr. Golden's analysis is no more meaningful than determining that constructing 100-story buildings is "routine" because every time someone has built such a building, they did the same thing: used up-to-date building materials, performed an economic analysis, obtained significant debt financing, hired tall cranes, and followed other similar practices. Because Mr. Golden's analysis does not look at the full range of the millions of maintenance, repair and replacement projects that utilities have undertaken, but instead cherry-picks only the largest and most extensive projects to use as a basis for comparison, his conclusions as to the routine "nature" of the PSD Projects are meaningless.

With respect to extent, Mr. Golden principally looks at whether the project was a "functionally equivalent replacement." *See* T.T., Sept. 28, 2010, at 52:15-22; *id.* at 53:9-11 (defining "functional equivalent" as "replacing component with components that perform the same function"). The "functionally equivalent" standard, however, has already been rejected by EPA and the courts. In 1990, as part of the *WEPCO* proceedings, EPA determined that a "functionally equivalent" replacement is essentially the same as the "like-kind" replacement: "EPA considers 'like kind replacements' to encompass the replacement of components . . . with the same (*or functionally similar*) components." PTX 1336 at CIN30B6RM0134 n.1(emphasis

added). EPA said that such "like-kind" or "functionally similar" replacement projects are not exempt as RMRR. The *WEPCO* decision also rejected the "functionally similar" standard. *WEPCO*, 893 F.2d at 908-909 (stating utility's definition of "like-kind replacement" as "replacement of equipment with equipment similar to that replaced" and rejecting utility's argument that like-kind replacements are exempt from PSD regulations).

Furthermore, the "functionally equivalent" standard eviscerates the statute. Large coal-fired boilers of the type at issue in these PSD cases are complex devices, and a utility can no more replace lower slope panels with a functionally different component like a pendant reheater than a transplant surgeon can replace a liver with a lung. Since large components are virtually always, by necessity, replaced with a "functionally equivalent" component, adopting this standard would exempt virtually all, if not all, projects and make the PSD statute a nullity.

Purpose. Mr. Golden's opinions on the purpose prong are unreliable because they ignore the majority legal standard and, if given effect, would undercut the principle that grandfathering of existing plants be limited and "not [] constitute a perpetual immunity from all standards under the PSD program." *Alabama Power Co. v. Costle*, 636 F.2d at 400. As noted in Argument section IV.D.2.b.ii above, the *Cinergy*, *Ohio Edison* and *Sierra Club* decisions have all held that the purpose of reducing outages and improving availability supports a finding that a project is not RMRR. These courts distinguished between (a) "routine maintenance" projects whose purpose was to maintain the condition of boiler tubes as they were, and (b) non-routine projects that were expected to improve the availability and condition of the generating units over a long period of time through improved materials and redesigns and thereby reduce maintenance costs. *See, e.g.*, *Cinergy*, 495 F. Supp. 2d at 938, 944, 946-47); *Ohio Edison*, 276 F. Supp. 2d at 860-61 (purpose factor weighs against RMRR when "the purpose of the activities was beyond mere

maintenance of the units" but was to "make them more available and reliable well into the future").

Mr. Golden's testimony nowhere addresses the majority standard distinguishing between projects that keep the unit in the same shape it had been in and projects that are designed to improve the unit. He testified about a number of possible "typical" purposes for projects that would presumably, in his mind, qualify them as RMRR: improving availability and reliability, addressing safety issues, and improving efficiency. T.T., Sept. 28, 2010, at 39:6-40:12. Under his standard, however, if large capital projects are RMRR simply because utilities perform them for a common purpose, then there is little or nothing left of the PSD program. Indeed, Allegheny replaced virtually the entire boiler at the Armstrong units to improve availability and reliability, *see*, *e.g.*, PTX 850 at 1, so under Mr. Golden's 'typical purpose' standard even those massive projects would be "routine maintenance, repair, or replacement."

Frequency. Mr. Golden's analysis of the "frequency" prong lacks probative value principally for the same reasons as his nature and extent and purpose analyses: he ignores the vast majority of the maintenance, repair and replacement projects that utilities undertake and fails to perform a careful analysis of the limited set of comparison projects that he does look at. In his analyses, he focused on capital projects at various utilities that exceeded $100,000 in cost. T.T., Sept. 28, 2010, at 64:16-20. He uses this threshold because it is the threshold EPA used in its section 114 document requests to utilities, but that just illustrates the overarching flaw in Mr. Golden's analysis. EPA selected that threshold to capture the largest projects – those that were large enough not to be "routine" – so if Mr. Golden, is correct, and those largest projects are RMRR, then, again, flies in the face of Congress' broad definition of "modification."

In fact, what Mr. Golden is doing is wrongfully applying the "prevalent or commonplace" in the industry standard that courts have repeatedly rejected. *New York v. American Elec. Power Serv. Corp.*, No. 2:04-cv-1098, 2007 WL 539536, at *2 (S.D. Ohio Feb. 15, 2007); *SIGECO*, 245 F. Supp. 2d at 1014-15. Mr. Golden never calculated the *frequency* of the projects by comparing the number of (comparable) projects with the total number of maintenance, repair and replacement projects in the industry. In particular, Mr. Golden never evaluated frequency of the large capital projects at issue in this case by comparison to the approximately 60 million smaller projects over the past 30 years that the utility industry has performed. T.T., Sept. 20, 2010, at 57:20-58:24.

Finally, Mr. Golden's frequency analysis is not meaningful because he does not examine frequency at the unit, which the courts and EPA have indicated is of central importance. *Compare* Argument section IV.D.2.b.iv above (courts focusing on frequency at the unit) *with* T.T., Sept. 28, 2010, at 57:13-73:7 (Mr. Golden's testimony about the frequency factor in which he says nothing about frequency at the unit).

Cost. Mr. Golden's opinions on the cost prong of the *WEPCO* test are flawed because he uses several invalid benchmarks for determining whether the cost of a project supports RMRR status: the cost of new generation, the "50 percent threshold" for the Hatfield's units and Mitchell 3, a WEPCO cost figure, a Beckjord 3 cost figure, a Stone & Webster figure for the cost of "life extension" projects, and an "expected annual capital investment" figure. T.T., Sept. 28, 2010, at 74:3-13; 75:4-10; 78:17-79:9. Those benchmarks lack legal foundation.

In particular, the notion that the cost of the massive *WEPCO* project is a relevant threshold has already been rejected: "nothing in WEPCO suggests that any project smaller than WEPCO will automatically qualify as routine maintenance, or that WEPCO was some type of

baseline for companies to compare [their] projects to in efforts to determine if they would qualify for routine maintenance." *SIGECO*, 245 F. Supp. 2d at 1017. Similarly, the cost of the Beckjord 3 project is not a threshold indicating that less expensive projects qualify for RMRR because, though Mr. Golden never mentioned it, a federal court has held on summary judgment that the Beckjord project was *not* RMRR. *Cinergy*, 495 F. Supp. 2d at 933-37. Thus, none of Mr. Golden's comparisons to the WEPCO and Beckjord 3 projects – whether on the cost factor alone or any of the other factors – have any legal significance. *See* T.T., Sept. 28, 2010, at 80:7-82:22 (Mr. Golden generally comparing the WEPCO and Beckjord 3 projects to the PSD Projects).

The expected annual capital investment figure that Mr. Golden presents actually supports a finding that the projects are not RMRR, as they show that the PSD Projects in most cases consumed much of or almost all of the expected capital investment for that year: the percentages range from Hatfield's Ferry lower slope and reheater projects costing 75 percent or more of the expected annual capital investment, to the Mitchell project costing 16 percent of the expected investment.[61] By way of analogy, if the Court spent 75 percent of its time in one year on one case, that case would hardly be "routine."

Finally, to the extent that Mr. Golden testified that "multi-million dollar" projects were "not at all unusual," he is again simply reducing the cost analysis to the "commonplace or prevalent in the industry" standard that, as shown above, has no legal merit and applying the "extraordinary" task standard that also has no merit. In sum, Mr. Golden's analyses on each of the *WEPCO* factors rely on irrelevant legal standards and fail to analyze relevant factual information, and as a result his RMRR opinions are not reliable.

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[61] Plaintiffs calculated these numbers by dividing the project cost listed on DTX 1874 by

V. ALLEGHENY IS LIABLE FOR VIOLATING THE PENNSYLVANIA NONATTAINMENT NEW SOURCE REVIEW REQUIREMENTS (CLAIM NOS. 3 AND 9)

A. Summary of Argument

The two principal elements that PA DEP must prove on its nonattainment NSR claims for the Armstrong plant are: (1) that the cost of the Reconstruction Projects exceeded 50 percent of the cost of a comparable entirely new facility, so that the Reconstruction Projects constituted "new sources," and (2) that Allegheny should reasonably have expected an increase in emissions of 40 tons or more from those new sources. PA DEP meets its burden on both points.

New Source. The Pennsylvania regulations use the same 50 percent "new source" test for the nonattainment NSR program as for the BAT program. Accordingly, the evidence plaintiffs have presented in support of their NSPS claims, and that PA DEP has presented in support of its BAT claims, *see* Argument sections II.D.1, II.D.2, II.D.3 and III.C above, also satisfies PA DEP's burden on this element of their nonattainment NSR claims. Allegheny's defenses and counterarguments on this element fail for the reasons already given in connection with those NSPS and BAT claims. *See* Argument sections II.E.1, II.E.2 and III.D above.

Emissions. Under the Pennsylvania regulations, the emission test for nonattainment NSR is not the actual-to-projected-future-actual test used under the PSD regulations. The test is more stringent: whether the "potential to emit" of the new source should be expected to exceed 40 tons per year. The potential to emit of a generating unit is calculated by assuming that the unit is run at full capacity – 100 percent availability and 100 percent utilization – for an entire year.

Once one has calculated the potential to emit of the new source, the Pennsylvania regulations provide for netting, in which the potential to emit can be reduced by creditable

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the higher of the two expected annual capital investment costs listed on that exhibit, $14.76.

emissions reductions, if any, from other activities. Thus, for example, when a project is so extensive that it meets the 50 percent test, one treats the reconstructed facility as a literally a brand new source, and one treats the facility before it was reconstructed as if it had been dismantled. The cessation in emissions from the dismantled facility can then be counted as a creditable reduction in emissions. Accordingly, one performs an "actual-to-potential" analysis: one calculates the potential-to-emit of the reconstructed new source and then subtracts the actual emissions during the pre-project period, representing the creditable cessation of emissions from the dismantled pre-reconstruction sources.

PA DEP meets its burden on this element through the actual-to-potential calculations that Dr. Rosen performed consistent with the Pennsylvania regulations. Even after netting, those calculations showed emissions increases of hundreds or thousands of tons, far exceeding the 40-ton threshold for both SO_2 and NO_x for both units.

B. <u>The Legal Standard</u>

In January 1994, PA DEP promulgated new nonattainment NSR preconstruction permit regulations. 24 Pa. Bull. 443 (Jan. 15, 1994) (promulgating 25 Pa. Code §§ 127.201-.216). These nonattainment NSR requirements apply to an existing facility in a nonattainment area for sulfur oxides[62] ("SO_x") or ozone that undertakes a "major modification." Under the regulations, a "major modification" is a physical change or change in the method of operation of a major facility that results in an increase in emissions equal to or exceeding certain emission rate thresholds. 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "major modification"). The regulations explain how to calculate emissions for the purpose of determining whether a new

[62] Sulfur oxides include a number of sulfur compounds, including SO_2. Accordingly, an SO_2 emissions calculation can serve as an SO_x calculation, although the SO_2 figure, because it does not count all sulfur oxides, would underestimate the total SO_x figure.

source is expected to cause emissions increases that exceed the thresholds. *See* 25 Pa. Code § 127.203(a)(2) (SO_x), § 127.203(b)(1)(ii) (NO_x as a precursor to ozone), 25 Pa. Code § 127.211(b), 25 Pa. Code §§ 127.207(1), (3)-(7) [all in PTX 2209 (d)]. The regulations provide that emissions increases are measured by reference to the generating unit's "potential to emit." 25 Pa. Code §§ 127.203(a)(2) & (b)(1)(ii) [PTX 2209 (d)].

Thus, with regard to SO_x, a major modification under the nonattainment NSR regulations occurs if an existing facility meets the following requirements: (1) it is located in a nonattainment area, (2) has the potential to emit 100 tons or more per year of SO_x, and (3) undertakes a modification, including the addition of a "new source," that results in an increase in the facility's potential to emit SO_x equal to or exceeding 40 tons per year, 1,000 pounds per day, or 100 pounds per hour, whichever is more restrictive. 25 Pa. Code §§ 127.203(a)(2) & 127.211(a)(1) [PTX 2209 (d)].

With regard to ozone, a major modification under the nonattainment NSR regulations occurs if an existing facility meets the following requirements: (1) it is located in a moderate nonattainment area for ozone, (2) has the potential to emit 100 tons or more per year of NO_x, and (3) installs a "new source" at the facility that results in an increase in the facility's potential to emit NO_x equal to or exceeding 40 tons per year, 1,000 pounds per day, or 100 pounds per hour, whichever is more restrictive. 25 Pa. Code §§ 127.203(b)(1) & 127.211(a)(2) [PTX 2209 (d)]. Units subject to nonattainment requirements must obtain a preconstruction permit and operate the unit using stringent LAER controls. 25 Pa. Code § 127.205 [PTX 2209 (d)]; *see also* 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "LAER").

Accordingly, under the regulations, PA DEP must prove five elements to establish liability on their nonattainment NSR claims at the Armstrong plant: (1) that the plant is a

facility; (2) that it was located in a nonattainment area; (3) that a "new source" was constructed at the facility, (4) that the new source should reasonably have been expected to increase the facility's potential-to-emit by 40 tons per year or more; and (5) that Allegheny did not comply with the nonattainment NSR requirements, among which are the requirement to obtain a preconstruction permit and operate the facility using stringent LAER controls. PA DEP bears the burden of proof on each of these elements.

C. The Evidence Demonstrates that Allegheny Violated the Pennsylvania Nonattainment NSR Regulations

1. The Armstrong Power Station Is a Facility

Under the regulations, the term "major facility" is defined to mean a facility that has the potential to emit a pollutant in an amount equal to or greater than an applicable annual emissions rate set forth in 25 Pa. Code § 127.203. *See* 25 Pa. Code § 121.1 (definition of "major facility"). The term "major NO_x emitting facility" is defined to mean, among other things, a facility which emits or has the potential to emit NO_x greater than 100 tons per year in an area included in an ozone transport region established under the Clean Air Act, 42 U.S.C. § 7511c. *See* 25 Pa. Code § 121.1 (definition of "major NO_x emitting facility"). PA DEP has met their burden on this issue because the parties have stipulated that the Armstrong plant is a "major facility" and a "major NO_x emitting facility." Docket Item 430 ¶ 5.

2. The Armstrong Power Station Is Located in a Nonattainment Area for SO_2 and Ozone

PA DEP has met its burden on this issue because Allegheny has stipulated that the Armstrong plant is in an area classified from 1978 throughout the time of the projects in the 1990s as nonattainment for SO_2 and moderate nonattainment for ozone. Docket Item 430 ¶¶ 12,

13. The area remains nonattainment for SO_2, Docket Item 430 ¶ 12, and is currently nonattainment for ozone under the 8-hour standard since June 15, 2004, *see* 40 C.F.R. § 81.339.

3. The Reconstructed Armstrong Units Are Each a New Source

As explained in Argument section III.B above, the Pennsylvania regulations define "new source" to include, among other things, a stationary air contamination source that was modified so that the fixed capital cost of new components exceeded 50 percent of the fixed capital costs that would be required to construct a comparable entirely new source. 25 Pa. Code § 121.1 [PTX 2208 (d)] (definition of "new source").

PA DEP has met its burden on this issue through the same evidence as the plaintiffs presented for the NSPS claims and that PA DEP relied on for its BAT claims: Allegheny's own characterization of the projects as "a total rebuild of the boilers," PTX 1222 at AE_DUN_00381331, and the opinions of Dr. Sahu and Mr. Larkin that the cost of the work far exceeded 50 percent of the cost of a comparable entirely new facility. *See* Argument sections II.D.1, II.D.2, II.D.3 and III.C above.

4. Allegheny Should Have Expected the Armstrong Reconstruction Projects to Produce Net Emissions Increases of Over 40 Tons Per Year of SO_x and NO_x

The Pennsylvania nonattainment NSR regulations expressly state that the test for whether a major modification occurs is whether the facility's potential-to-emit is expected to increase more than 40 tons per year or more as a result of the project. *See* 25 Pa. Code § 127.203(a)(2) [PTX 2209 (d)] (SO_x); 25 Pa. Code § 127.203(b)(1) [PTX 2209 (d)] (NO_x as a precursor to ozone). In particular, the Pennsylvania regulations define "potential to emit" as "the maximum capacity of a source to emit a pollutant under its physical and operational design." 25 Pa. Code. § 121.1 [PTX 2208 (d)] (definition of "potential to emit"). Other provisions of the regulations

allow for “netting,” which consists of adjusting the potential-to-emit calculation by the amount of certain emissions increases or decreases other than those for the project. *See* 25 Pa. Code § 127.211(b)(2) & (b)(3)(iii)(B)(I) [PTX 2209 (d)].

PA DEP has met its burden on this element through the opinions of Dr. Rosen , who testified that Allegheny should have expected the Reconstruction Projects to increase SO_2 and NO_x emissions to increase, under the potential-to-emit test, by well over 40 tons per year. Specifically, Dr. Rosen projected the following emissions increases in tons per year:

Unit	**SO_2**	**NO_x (High NO_x)**	**NO_x (Low NO_x)**
Armstrong 1	6,449	1,864	790
Armstrong 2	5,579	2,024	916

T.T., Sept. 21, 2010, at 107:11-109:1; PTX 2176.

As noted above, the Pennsylvania nonattainment NSR regulations require calculating the potential-to-emit of the new source and then allow netting out of that figure any creditable emissions increases or decreases, and Dr. Rosen’s calculations do exactly that. As the post-project emissions amounts, Dr. Rosen used the units’ potential to emit. T.T., Sept. 21, 2010, at 105:18-106:4. The regulations define potential to emit as the unit’s emissions operating at maximum capacity, and Dr. Rosen calculated the post-project potential to emit of the new source at maximum capacity, assuming 100 percent availability and 100 percent utilization for a 100 percent capacity factor. *Id.* at 106:5-7, 106:16-107:10. Dr. Rosen then reduced the potential to emit by subtracting the pre-project emissions amounts using his average generation baseline approach. *Id.* at 106:8-15. This represents netting of the reduction in emissions caused by the removal of the old source – the original pre-project boiler that Allegheny tore down before installing the new reconstructed boiler. Because Dr. Rosen’s emissions calculations follow the

requirements of the Pennsylvania nonattainment NSR regulations, and were calculated using his reasonable five-equation methodology and Allegheny's own data, those calculations are a reasonable estimate of what Allegheny should have forecast the effect of the Armstrong Reconstruction Projects would be under the potential-to-emit test.

5. Allegheny Has Not Complied with the Nonattainment NSR Requirements

PA DEP has met its burden on this element because Allegheny has not obtained a nonattainment NSR permit or plan approval for the Armstrong Reconstruction Projects and did not operate the Armstrong generating units subject to LAER after completion of those projects. *See* PTX 2 ¶¶ 158, 159, 160, 162, (Armstrong 1); *id.* ¶¶ 221, 223, 224, 225 (Armstrong 2).

VI. ALLEGHENY IS LIABLE FOR VIOLATION OF THE FEDERAL AND PENNSYLVANIA TITLE V REQUIREMENTS (CLAIM NOS. 13-14, 21-22 AND 25-26)

A. Summary of Argument

The 1990 Clean Air Act amendments required that operators of large air pollution sources obtain Title V operating permits. Title V permits do not impose any additional operating restrictions but simply collect in one document all of the applicable operating requirements embodied in various other permits and regulations that govern the plant's operation.

To obtain Title V permits, the operators of the facilities had to file detailed Title V permit applications identifying each of the applicable requirements for the facility and certify that the facility was operating in compliance with those applicable requirements. The regulations also required that an operator provide supplemental information after filing the application if the original application was incomplete or if the source became subject to additional requirements.

As shown in Argument sections II through V above, the Armstrong, Hatfield's Ferry and Mitchell power stations became subject to PSD requirements during the 1990s, and the

Armstrong plant became subject to NSPS, BAT and nonattainment NSR requirements as well. Allegheny never reported those applicable requirements, or the projects that triggered those requirements, in the Title V applications it submitted to PA DEP in 1995. Nor did Allegheny subsequently provide additional information to reflect those projects.

Because of Allegheny's failure to report the information required under the Title V requirements, the Title V permits that PA DEP eventually issued did not contain all applicable requirements. Accordingly, Allegheny has been operating its plants in violation of the Title V requirements. Aside from claiming that plaintiffs have not pled a proper Title V claim, which the Court rejected, *see* Docket Item 45 at 12-16, *as adopted by* Docket Item 50, Allegheny has not formally set out any defenses specific to the Title V claims.

B. <u>The Legal Standard</u>

The Pennsylvania SIP requires that the operator of a Title V facility include the following information in an application for a Title V operating permit:

(1) a citation and description of applicable air pollution control requirements;

(2) other specific information that may be necessary to implement and enforce applicable requirements of the Clean Air Act or Pennsylvania SIP or to determine the applicability of such requirements; and

(3) a compliance plan, including a description of the compliance status with respect to applicable requirements and a schedule for coming into compliance with requirements for which the facility is not in compliance.

25 Pa. Code §§ 127.503(4), (5) & (8) [PTX 2209 (d)]; *see also* 40 C.F.R. §§ 70.5(c)(4), (5) & (8); 40 C.F.R. §§ 71.5(c)(4), (5) & (8) (same requirements under federal regulations). "Applicable requirements" include requirements in the Pennsylvania SIP, applicable NSPS standards, and terms of a PSD or nonattainment NSR permit. 25 Pa. Code §§ 127.503(4), (5) & (8); *see also* 25 Pa. Code § 127.441 [PTX 2209 (d)]; 40 C.F.R. §§ 70.2 & 71.2.

A Title V application must also include a certification of compliance with applicable requirements and a certification as to truth, accuracy and completeness, both by a responsible official of the entity seeking the permit. 25 Pa. Code § 127.503(10); *see also* 40 C.F.R. §§ 70.5(c)(9) & (d); 40 C.F.R. §§ 71.5(c)(9) & (d) (same requirements under federal regulations).

After a Title V permit application is filed, the applicant must update the application as appropriate with (1) information about requirements that become applicable after the application is filed, and (2) information necessary to remedy omissions of relevant facts or incorrect information in the application. 25 Pa. Code § 127.414(a) [PTX 2209 (d)] (new applicable requirements) (as made federal law by 40 C.F.R. §§ 52.2020-.2063); *see also* 25 Pa. Code § 127.414(c) [PTX 2209 (d)] (changes occurring at the facility) (as made federal law by 40 C.F.R. §§ 52.2020-.2063); 40 C.F.R. §§ 70.5(b) & 71.5(b); 25 Pa. Code § 127.414(b) [PTX 2209 (d)] (correction of omissions or incorrect information) (as made federal law by 40 C.F.R. §§ 52.2020-.2063); *see also* 40 C.F.R. §§ 70.5(b) & 71.5(b).

The actual Title V operating permits must include "emission limitations and standards" and any other operating conditions necessary to assure compliance with the "applicable requirements." 42 U.S.C. § 7661c(a); 40 C.F.R. §§ 70.6(a)(1) & 71.6(a)(1); 25 Pa. Code § 127.502(a) [PTX 2209 (d)]. The permits must also contain a compliance schedule regarding applicable requirements for which the facility is not in compliance. 25 Pa. Code § 127.513(3) [PTX 2209 (d); *see also* 40 C.F.R. §§ 70.6(c)(3) & 71.6(c)(3). It is unlawful to operate a source in violation of the Title V operating permit requirements. 25 Pa. Code § 127.512(c)(1) [PTX 2209 (d) (as made federal law by 40 C.F.R. §§ 52.2020-.2063); *see also* 42 U.S.C. § 7661a(a); 40 C.F.R. §§ 70.1(b), 71.1(b) & 71.12.

Accordingly, under the regulations, plaintiffs must prove three elements to establish liability on their PSD claims at the Armstrong, Hatfield's Ferry and Mitchell plants: (1) that there was at least one applicable requirement that Allegheny's failed to disclose in its Title V application or in any supplemental submission to PA DEP; (2) that as a result of Allegheny's failure to disclose, the applicable requirement was not included in Allegheny's Title V permit; and (3) Allegheny has not complied with the undisclosed requirement. Plaintiffs may also prove a violation by showing that Allegheny's certification of compliance with applicable requirements and certification as to truth, accuracy and completeness were not accurate. Plaintiffs bear the burden of proof on these elements.

C. <u>The Evidence Proves that Allegheny Violated the Title V Requirements</u>

Plaintiffs' evidence establishes the three elements of liability for plaintiffs' Title V claims. With regard to the first element, as shown above, Armstrong became subject to NSPS, BACT (PSD), nonattainment NSR and BAT emissions requirements after work performed in 1995 and 1994/1996 (the "new Armstrong applicable requirements"). Similarly, the Hatfield's Ferry and Mitchell plants became subject to BACT (PSD) emissions requirements after work performed in 1993, 1996, 1997 and 1999 at Hatfield's Ferry and in 1994 at Mitchell (collectively with the "new Armstrong applicable requirements," the "new applicable requirements")

Allegheny did not, however, describe the new applicable requirements in its July 1995 Title V permit applications for Armstrong, Hatfield's Ferry or Mitchell or in any subsequent disclosure relating to those applications. Specifically, Allegheny did not include in its application: (1) a citation and description of the new applicable requirements; (2) information about the Reconstruction and PSD Projects necessary for PA DEP to evaluate the applicability of any air pollution control requirements; or (3) a compliance plan showing how Allegheny planned

to come into compliance with the new applicable requirements. *See* PTX 1210 *passim*; PTX 1207 *passim* (Hatfield's Ferry); PTX 1213 *passim* (Mitchell).

Allegheny also failed to submit certification of compliance with applicable requirements that addressed its failure to meet the new applicable requirements. PTX 1210 at AE_HQ_00136782; PTX 1207 at AE_HQ_00591517; PTX 1213 at AE_HQ_00133450. In failing to acknowledge that it had undertaken modifications and reconstructions that triggered those requirements, Allegheny's certifications that its applications were true, accurate and complete were inaccurate. *See* PTX 1210 at AE_HQ_00136678; PTX 1207 at AE_HQ_00591391; PTX 1213 at AE_HQ_00133328. After filing its Title V applications, Allegheny did not supplement the application with information regarding the modifications and reconstructions or the requirements that the modifications and reconstructions triggered, and in particular did not supplement the applications with information about the Hatfield's Ferry projects that occurred in 1996, 1997 and 1999 after Allegheny submitted the applications.

Plaintiffs also have proven the second element. Because Allegheny failed to provide the information called for by the Title V regulations, the operating permits issued for the Armstrong and Hatfield's Ferry facilities in July 2001 and for the Mitchell facility in March 2002 did not include all "applicable requirements," and in particular did not include the new applicable requirements or a schedule for compliance with those requirements.

Finally, plaintiffs have proven the third element. As shown in Argument sections II.C.4, III.C, IV.C.5 and V.C.5 above, Allegheny has not complied with the new applicable requirements. Therefore, since no later than the date the Title V permits were issued, Allegheny has been operating in violation of the Title V provisions of the federal Clean Air Act and Pennsylvania law.

VII. ALLEGHENY'S FAIR NOTICE DEFENSE FAILS AS A MATTER OF LAW AND FOR LACK OF FACTUAL SUPPORT

A. Summary of Argument

Every court to have considered the fair-notice defense in the context of PSD litigation has rejected it. This Court should reach the same result.

With respect to the RMRR defense, courts have found that utilities were on notice of the narrow, *de minimis* scope of the exemption by the early 1990s, before any of the projects at issue in this case. For example, in 1989, the utility industry's air pollution lobbying organization, the Utility Air Regulatory Group, or UARG, acknowledged that EPA interpreted the RMRR exemption to "include only those [projects] that (1) are frequently done at that plant, (2) involve no major equipment, (3) are inexpensive, and (4) do not extend the life of the plant." Thus, four years before Allegheny undertook any of the projects in this case, the industry was on notice of the narrow interpretation plaintiffs rely on in this case.

Allegheny may also claim lack of fair notice with respect to the standard for determining whether there is a significant net emissions increase for PSD purposes. The relevant legal question is not whether the utility had notice of the "precise methodology for calculating emissions," but whether it was "aware of the regulatory standards for determining whether a project may result in significant increases in emissions." *United States v. Cinergy Corp.*, 495 F. Supp. 2d 892, 906 (S.D. Ind. 2007). Plaintiffs' contention in this case is that a project triggers PSD applicability if the project is expected to increase the amount of time that a generating unit is operated and thereby increase emissions from the unit. In 1988 and 1989, four years before any of the projects in this case EPA informed utilities that PSD applicability could be triggered in exactly that way. Accordingly, Allegheny had fair notice of the relevant regulatory standard.

B. The Legal Standard

"[A] regulated party has fair notice of an agency's interpretation of regulations if, by reviewing the regulations and other public statements issued by the agency, the party is able to identify with 'ascertainable certainty' the standards with which the agency expects the party to conform." *Cinergy*, 495 F. Supp. 2d at 900 (quoting *General Elec. Co. v. EPA*, 53 F.3d 1324, 1329 (D.C. Cir.1995)). Factors courts have found relevant to the question of fair notice are "the plain language of the regulation, other public statements by the agency, the consistency of the agency's public statements, an agency's pre-enforcement efforts to bring about compliance, confusion within the agency as to the proper interpretation, and whether or not a confused party makes an inquiry about the meaning of the regulation." *Cinergy*, 495 F. Supp. at 900-901; *see also United States v. Southern Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1011-12 (S.D. Ind. 2003) (citing cases) (hereinafter "*SIGECO*"). Because Allegheny has raised the issue of fair notice as an affirmative defense, Allegheny has the burden of proof. *Cinergy*, 495 F. Supp. 2d at 901; *United States v. Ohio Edison Co.*, 276 F.Supp.2d 829, 886 (S.D. Ohio 2003). Allegheny fails to meet that burden, however, with respect to the regulatory standards for both the RMRR exemption and PSD emissions increases.

C. Allegheny Had Fair Notice of the Correct RMRR Standard

Every court to have evaluated the fair notice defense in the context of the RMRR regulations has rejected it. *United States v. Alabama Power Co.*, 681 F. Supp. 2d 1292, 1313 n.22 (N.D. Ala. 2008); *Cinergy Corp.*, 495 F. Supp. 2d at 901-909; *Ohio Edison*, 276 F. Supp. 2d at 885-889; *SIGECO*, 245 F. Supp. 2d at 1011-24; *see also United States v. Alabama Power Co.*, 372 F. Supp. 2d 1283, 1294 n.21 (N.D. Ala. 2005) (declining to consider RMRR fair-notice defense because it is not "a particularly strong argument").

In rejecting the defense, courts have concluded that the statute, the regulation, EPA determinations and court decisions put the utility industry on notice as of 1990, at the latest, of the narrow RMRR interpretation that plaintiffs assert here. As described in Argument section IV.B.1 above, the 1977 statute itself provides an expansive definition of "modification." The 1980 regulation, in turn, only creates an exclusion for "routine" projects. Inflating the RMRR exemption to cover thousands of projects involving replacement of major components would thus "vitiate the very language of the CAA itself" and thereby produce a result that "could not have been intended by Congress. *Ohio Edison*, 276 F. Supp. 2d at 888. Thus, the expansiveness of the statute's reach put Allegheny on notice that a broad interpretation of RMRR conflicts with the statutory language and would be invalid. *Id.* The D.C. Circuit's 1979 decision in *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), also put the utility industry on notice that only "*de minimis*" exceptions would qualify for the RMRR exemption. *See Ohio Edison*, 276 F. Supp. 2d at 888; *see also SIGECO*, 245 F. Supp. 2d at 1014 (noting that *Alabama Power* struck down EPA regulations that excluded projects that were not "major").

A September 1988 memorandum written by EPA official Don Clay regarding the proposed modifications at the Wisconsin Electric Power Company (the "Clay memorandum") "notified the regulated community that the EPA considered routine maintenance to be a narrow exemption" because it expressly characterized the exemption as a "very narrow exclusion." *SIGECO*, 245 F. Supp. 2d at 1019; *see also Ohio Edison*, 276 F. Supp. 2d at 888-89.

A 1989 document from the utility industry itself confirms that the industry had notice of the narrow RMRR interpretation used by plaintiffs here. *SIGECO*, 245 F. Supp. 2d at 1019. The Utility Air Regulatory Group, or UARG, is an industry trade group which tracks federal air regulatory issues; Allegheny was a member during the 1980s and 1990s. *See* PTX 476 at i

(UARG self-description), PTX 179 at UARG1 0000094, n.1 (same); PTX 477 at 1 (Allegheny senior executive Peter Skrgic speaking in 1991 as "the representative of UARG"); PTX 480 at AE-UARG1-000062(agenda from Allegheny files for June 14, 1989 UARG committee meeting referencing report concerning "New Source Permitting . . . (including Plant Renovation Issues)"). In June 1989, in response to the 1988 Clay memorandum, UARG wrote an advocacy paper in which it noted EPA's position that RMRR activities "include only those that (1) are frequently done at that plant, (2) involve no major equipment, (3) are inexpensive, and (4) do not extend the life of the plant." PTX 179 at UARG1 0000095. That narrow interpretation of the RMRR exclusion is the one that plaintiffs are asserting in this case, and based on this UARG document, as the *SIGECO* court found, the utility industry had notice of it as of 1989. *SIGECO*, 245 F. Supp. 2d at 1019.

Finally, the Seventh Circuit's January 1990 decision in *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) (hereinafter, "*WEPCO*"), which upheld the RMRR interpretation set out in the Clay memorandum, constitutes further proof that the utility industry was on notice of the narrow scope of the RMRR exemption. *SIGECO*, 245 F. Supp. 2d at 1017 (the *WEPCO* decision "is significant because it expresses the EPA's interpretation of routine maintenance"); *Ohio Edison*, 276 F. Supp. 2d at 889 ("the Clay Memo and the Seventh Circuit's subsequent *WEPCO* decision in 1990 put the regulated community on notice that the routine maintenance exemption was subject to a narrow, rather than an expansive, interpretation"). Based on this evidence, the courts have held that utility industry has had fair notice from no later than 1990 of the narrow interpretation of the RMRR exclusion that plaintiffs rely on in this case. *SIGECO*, 245 F. Supp. 2d at 1024; *see also Ohio Edison Co.*, 276 F.Supp.2d at 889 (finding unavailing defendant's assertion that it lacked fair notice of the RMRR exemption).

None of the evidence Allegheny presented negates the fact that Allegheny, like other utilities, had notice of the narrow interpretation of the RMRR exclusion relied on by plaintiffs here. Allegheny will likely rely on testimony from its past and current employees as to what they understood the RMRR exclusion to cover. Their testimony, however, is not probative on fair notice issues because none of them testified about what notice Allegheny did or did not receive. Instead, they testified about their understanding of the RMRR test. *See, e.g.*, T.T., Sept. 23, 2010, at 155:10-18; T.T., Sept. 27, 2010, at 123:23-124:5. None of Allegheny's witnesses testified, however, about how they arrived at that understanding, and in particular none of them testified that they had based their understanding on any statute, regulation, guidance or other document or communication from EPA or PA DEP.

Indeed, in this context, it is telling that Allegheny presented no testimony from the employees who would have been most familiar with the RMRR exemption: its environmental compliance staff and its legal staff. In particular, Allegheny did not call Jeannine Hammer, who, according to Mr. Colby, was the Allegheny environmental compliance person "primarily responsible" for permitting issues at the time of the projects, T.T., Sept. 23, 2010, at 144:25-145:3, and who, to plaintiffs' knowledge, still works for Allegheny.

In fact, the testimony Allegheny presented demonstrates Allegheny's inadequate efforts to comply with the law, not lack of notice. In 1990, three years before any of the projects in this case, the *WEPCO* decision held that "like-kind" replacements did not constitute RMRR. *WEPCO*, 894 F.2d at 907-13; *see also* PTX 1336 at CIN30B6RM0134 n.1 (1990 EPA letter defining like-kind replacements as the replacement of components with "the same (or functionally similar) components" and stating that such replacements would be subject to PSD requirements under the actual-to-projected actual emissions test). Both Mr. Colby and Mr.

Maiden, however, testified that they understood the PSD Projects to be excluded from PSD requirements because they were like-kind replacements. T.T., Sept. 23, 2010, at 155:10-18 (Mr. Colby: "if you were just doing routine maintenance or replacements of components *in kind*, that you were exempt from the permitting" (emphasis added)); T.T., Sept. 27, 2010, at 124:2-5 (Mr. Maiden testifying as to his understanding of the RMRR exemption: "Well, like *inkind* replacements. . . . Any kind of *inkind* replacement." (emphasis added)). If years after the 1990 *WEPCO* decision, in the period from 1993 to 1999 when Allegheny was undertaking the PSD Projects, Allegheny's employees still believed that like-kind replacements automatically constituted RMRR, that is evidence of Allegheny's failure to monitor the law and educate its staff, not evidence of inadequate notice.

In addition, Mr. Colby also testified that, in his view, the Hatfield's Ferry and Mitchell 3 PSD Projects were exempt as RMRR because Allegheny was not "doing anything to increase the steaming capacity or the operation of the boiler." T.T., Sept. 23, 2010, at 159:3-15. Mr. Colby does not state where he got this test for applicability of the RMRR defense, and to plaintiffs' knowledge, there is no EPA or PA DEP guidance document that indicated that the factors Mr. Colby identified play any role in the RMRR exception.

Finally, in determining whether there is fair notice, courts look to whether a regulated entity asks the regulatory authority questions about the meaning of purportedly ambiguous regulation. *See*, *e.g. Cinergy*, 495 F. Supp. at 900-901; *SIGECO*, 245 F. Supp. 2d at 1011-12. To plaintiffs' knowledge, there is no testimony or other evidence that Allegheny ever asked any such questions with regard to the RMRR exemption. In sum, then, the testimony of Allegheny's witnesses does not demonstrate lack of notice, but instead demonstrates Allegheny's failure to heed the public notice that was available. Allegheny's fair notice defense fails on that ground

alone, since "[a] claim of lack of notice 'may be overcome in any specific case where reasonable persons would know their conduct is at risk'." *United States v. Hoechst Celanese Corp.*, 128 F.3d 216, 224 (4th Cir. 1997) (quoting *Maynard v. Cartwright*, 486 U.S. 356, 361 (1988)).

In addition to the testimony of its current and former employees, Allegheny will likely rely on the testimony of its expert, Mr. Golden, but the courts have already heard and rejected his arguments. Mr. Golden testified about several documents: a 1990 General Accounting Office ("GAO") report; a 1991 letter from an EPA official to Congressman Dingell, and a 1989 letter from the EPA Administrator to Congressman Dingell. T.T., Sept. 28, 2010, at 15:21-17:8, 21:9-30:16, 30:24-32:13.

As for the 1990 GAO report, the *SIGECO* court concluded that it:

> says little, if anything at all, about the EPA's interpretations of routine maintenance. . . . The report cites two reasons the WEPCO ruling would not be applied broadly: (1) because many projects do not result in increased emissions; and (2) because other projects qualify for routine maintenance. The letter does not construe the routine maintenance exemption; it simply reaffirms WEPCO and explains why the EPA did not think it would not affect most utilities. Moreover, as the Government argues, even if it did, it is an anonymous statement that does not purport to give the EPA's official view.

SIGECO, 245 F. Supp. 2d at 1020. Thus, the report does not constitute an official EPA statement that would be relevant for fair notice purposes.

The 1989 and 1991 letters from EPA to Congressman Dingell are equally irrelevant. The 1991 letter states that most utility projects would not be similar to the *WEPCO* projects and that the *WEPCO* decision was not expected to significantly affect power plant life extension projects. DTX 196 at 6. But this letter does not constitute an EPA statement regarding the meaning of the RMRR exemption because it does not purport to interpret the exemption. *SIGECO*, 245 F. Supp. 2d at 1020. Mr. Golden's follow-up testimony, that after its 1991 letter EPA understood that

some life-extension projects could be excluded from PSD requirements as RMRR, T.T., Sept. 28, 2010, at 32:8-13, is not probative: the question is not whether *some* projects are subject to the RMRR exemption, but *which ones*, and the letter does not provide any guidance on that issue.

Similarly, the 1989 letter does not address the RMRR exemption, other than (1) noting that some projects would qualify for the exemption, DTX 141 at 3, and (2) endorsing the positions that EPA took in the WEPCO matter, *id.* In any event, a letter to a member of Congress is not regulatory guidance, and no witness testified that the utility industry or Allegheny used either of these letter or the GAO report as guidance at the time. In sum, then, the documents Mr. Golden testified about do not constitute EPA guidance to the regulated community, let alone guidance that indicates which projects qualify for the RMRR exemption.

To the extent that Allegheny seeks to invoke trial or deposition testimony from PA DEP employees, such testimony is not relevant to fair notice issues: "[p]ost-publication discourse among [agency] staff about the meaning of the . . . regulations" is irrelevant to whether a defendant should have understood whether his action was covered by the regulations, since to resolve that question, "the court need look only to the language of the regulation and any official, public interpretations of it." *United States v. Farley*, 11 F.3d 1385, 1391 (7th Cir. 1993). Following *Farley*, at least one court has declined to consider the statements of agency employees in determining fair notice issues in new source review litigation. *Cinergy*, 495 F. Supp. at 895 n.2. To the extent that Allegheny relies upon statements that are contrary to the governing *WEPCO* standard, it is well established that "an isolated opinion of an agency official does not authorize a court to read a regulation inconsistently with its language." *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 580-81 (2007).

That exclusionary rule applies with particular force here. "The notice that matters for the fair notice doctrine are the statements the defendant receives *before* the alleged violation begins." *SIGECO*, 245 F. Supp. 2d at 1024 (emphasis added); *see also id.* at 1021 (it is "anomalous" for a utility asserting a fair notice defense to rely on statements received after the project was completed). None of the testimony at issue, however, concerns PA DEP statements made before the projects. *See, e.g.*, D.T. (Kenneth Bowman), July 31, 2007, at 45:13-46:13 (PA DEP witness unaware of any PA DEP policies regarding the RMRR exemption).

Finally, Allegheny may also rely on applicability determinations or similar documents from EPA or PA DEP, including documents concerning projects at a power station owned by another company, the AES Beaver Valley facility. No Allegheny witness testified that Allegheny knew about any PA DEP determination regarding that project before plaintiffs filed this litigation in 2005. Indeed, to plaintiffs' knowledge, Allegheny obtained all of the documents it may rely on as support for its fair notice defense after 2000, through discovery in this case or other new source review cases.[63] As with the testimony of the PA DEP witnesses, documents that Allegheny obtained in the 2000s do not establish that Allegheny lacked notice in the 1990s.

Finally, Allegheny may argue that the 'change' in regulatory interpretation of which it lacked fair notice was in the late 1990s, when the federal government and some state governments began efforts to investigate and litigate PSD and nonattainment NSR violations at coal-fired power plants. But the courts have unanimously found that the utility industry had notice of the standard that plaintiffs in this case and the other PSD and nonattainment NSR cases

[63] The Court can verify whether a document came from Allegheny's own files by looking at the Bates number: if the Bates number starts with "AE" or "R-", the document came from Allegheny's files; if the Bates number starts with some other prefix, then the document came from some other entity. For example, Allegheny obtained documents with Bates numbers beginning with the prefix "PA" from PA DEP's files during discovery in this case.

are applying as of no later than late 1980s or early 1990s, when the Clay memorandum and the WEPCO decision were issued. So this argument, like Allegheny's other arguments, fails.

D. There Was No Requirement that EPA or PA DEP Promulgate the Interpretation of the RMRR Exemption Through a Notice-and-Comment Rulemaking Process

Allegheny may argue that any notice it received through the Clay memorandum was not sufficient, and that the only lawful way for EPA or PA DEP to purportedly "change" position regarding the interpretation of the RMRR regulations was through notice-and-comment rulemaking. *See, e.g.*, PTX 2 at 43 (sixth affirmative defense). The Third Circuit has rejected the argument that agencies need to go through notice-and-comment rulemaking to set out regulatory interpretations. *Beazer East, Inc. v. EPA, Region 3*, 963 F.2d 603, 605 n.2, 606-607 (3d Cir. 1992) (holding that interpretation of regulatory exception that EPA had adopted in the "Weddle memorandum" was exempt from notice and comment requirements because it was an "interpretive rule[ ] or statement[ ] of policy"); *Sekula v. Fed. Deposit Ins. Corp.*, 39 F.3d 448, 457 (3d Cir. 1994) (holding that notice-and-comment rulemaking was not required when agency interpretations "did not change the meaning of the regulation" but only "explained and clarified it"; and further holding that "agency manuals, guidelines, and memoranda are interpretive rules not subject to the [Administrative Procedure Act].").

E. Allegheny Had Fair Notice of the PSD Emissions Standard

Allegheny's fair notice defense with regard to the PSD emissions standard is equally flawed. Allegheny cannot show that it lacked fair notice that the PSD emissions test concerned increases in annual emissions. Next, Allegheny's contention that that it did not have notice of the specific methodology that Dr. Rosen used in this case is a 'red herring.' The one court to have evaluated the fair-notice defense in the context of the PSD emissions test rejected both of

these arguments as a matter of law, granting summary judgment in favor of the United States and against the utility on the defense. *Cinergy*, 495 F. Supp. 2d at 906-909. There is no basis in the law or in the evidence presented in this case for this Court to come to a different conclusion.

1. Allegheny Had Fair Notice that PSD Test Established an Annual Emissions Test, Not an Hourly Test

Any Allegheny contention that it reasonably understood the emissions prong of the NSR liability standard to be evaluated under an hourly emissions test, not an annual test, is legally and factually baseless: Allegheny understood since at least 1990 that the test was annual.

As a legal matter, the contention that the PSD emissions standard is evaluated under an hourly test is unreasonable because, as the Supreme Court has held, the plain language of the NSR regulations are unambiguous: the regulations "clearly do not define a 'major modification' in terms of an increase in the 'hourly emissions rate,'" and, in fact, "the regulatory language simply cannot be squared with a regime under which 'hourly rate of emissions,' . . . is dispositive." *Environmental Defense v. Duke Energy Corp.* 549 U.S 561, 577, 578 (2007). As a matter of logic, Allegheny cannot establish a fair-notice defense by claiming it reasonably understood the regulation to set out an hourly test when the regulation cannot reasonably be read to set out an hourly test.[64]

At a public panel discussion in 2007, two days after the Supreme Court issued the *Duke Energy* decision, one of Allegheny's lawyers in this matter at the time, William Bumpers, confirmed that the regulatory language unambiguously provided for an annual test and that the utility industry invented the purported hourly test after the fact for the purpose of litigation:

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[64] While as a procedural matter the Supreme Court stated that it was not ruling on the "fair notice" issue, *Duke Energy*, 549 U.S. at 581-82, for all the reasons set out in this brief there is no credible argument that the utility industry did not have fair notice of the emissions test.

> You know, I represent a lot of power plant industry in America and have been helping them understand New Source Review and how to comply with it and occasionally having to defend them against enforcement suits or citizen action suits. And I was not at all surprised by the [*Duke Energy*] decision.
>
> * * *
>
> . . . I think, and some of my clients will probably fire me for saying this, this was a fairly ex post argument that we created because I agreed with the dicta, and I do believe it's a dicta, in the great part of the [*Duke Energy*] opinion that says, look, if you read EPA's regulatory scheme, the PSD, they've anticipated and dealt with this as an annual emissions test from the get-go.
>
> And, in fact, I have been advising my clients since 1990 that you always look at it in terms of actual emissions increase. So it was a very good argument and I think there's merit to it. I don't want to say it was - well, there's no merit to it anymore, but I thought there was merit to it when we put it together. It was tremendously clever.

PTX 170 at 37:03-37:19, 38:21-39:06 (video), PTX 171 at 35:13-18, 36:16-37:7 (transcript). A "tremendously clever," "ex post" argument that litigation counsel "put . . . together" after the fact cannot form the basis for a fair-notice defense.

Mr. Bumpers' statement is consistent with the historical record. In a February 1989 EPA applicability determination letter to John Boston, a WEPCO executive (the "Boston letter"), EPA expressly rejected the utility's contention that the PSD regulations relied on an hourly test: "the results of testing conducted by WEPCO, intended to determine current maximum hourly capacity, have no impact on the existence of a significant net emissions increase for PSD purposes." PTX 141 at 9. EPA repeated the point two paragraphs later: "The hourly capacity demonstration for NSPS purposes is not relevant to the PSD analysis." *Id.* at 10.

Moreover, as a factual matter, at all times relevant to this litigation, Allegheny understood that the PSD regulations set an annual emission test. An Allegheny memorandum

written by one of its environmental compliance staff in April 1990 – three years before any of PSD Projects, and two years before the 1992 WEPCO rule – identified the "fundamental differences" between the modification provisions of the NSPS program and those of the PSD program:

> Emissions increases for NSPS purposes are determined by changes in the hourly emissions rate at maximum capacity. The PSD looks at *total annual emissions* to the atmosphere. Emissions increases under PSD are determined by *changes in annual emissions* to the air.

PTX 586 at AE_HQ_00594969 (emphasis added).

The Mooney memorandum from July 1993 – again, before any of the PSD Projects – confirms that Allegheny understood that "the PSD program criteria used to determine mandatory compliance differs from the NSPS program," since "[f]or PSD, *any increase in total annual emissions (tons per year)* will require the used of Best Available Control Technology (BACT)." PTX 256 at AE_ARM00132855 – AE_ARM00132856 (emphasis added). Thus, when Mr. Mooney performed the only Allegheny attempt at a PSD analysis for any of the PSD Projects, he evaluated the effect on annual emissions, not hourly emissions. *Id.* at AE_ARM00132856

In sum, any argument that Allegheny did not have notice of the annual emissions standard for PSD applicability is meritless.

2. Allegheny Had Fair Notice of the Regulatory Standards for Determining Whether a Project Would Be Anticipated to Increase Emissions

Allegheny's contention that it cannot be held liable for PSD violations because it lacked fair notice of the specific methodology that Dr. Rosen used in this case is erroneous. The

Cinergy court rejected that argument on summary judgment, and there is no factual or legal basis for a different ruling here.

The *Cinergy* court first held that the relevant test is not whether the defendant utility had notice of the "precise methodology for calculating emissions," but whether the utility was "aware of the regulatory standards for determining whether a project may result in significant emissions." *Cinergy*, 495 F. Supp. 2d at 906. The *Cinergy* court followed the reasoning of the *Ohio Edison* court, which, in ruling on the merits, had held that "so long as the defendant could have predicted that its projects would result in a substantial increase in emissions, the precise computation was not relevant. " *Id.* (citing *Ohio Edison*, 276 F. Supp. 2d at 880). The *Cinergy* court accordingly concluded that, for fair notice purposes, the utility's "understanding of the exact mathematical formula is irrelevant." *Id.*

Applying the *Cinergy* standard in this case, Allegheny had fair notice of the regulatory standards for determining whether a project would cause a significant emissions increase. *Id.* at 906. As explained above, plaintiffs assert that Allegheny is liable for PSD violations because it reasonably should have expected increases in usage of the Armstrong, Hatfield's Ferry and Mitchell 3 units as a result of the PSD Projects and therefore should have expected increases in emissions. *See* Background and Facts section IV.C and Argument section IV.C.3 above. EPA guidance has set out that theory of PSD applicability since at least the late 1980s.

In the 1989 Boston letter, EPA specifically stated that an increase in hours of operation, if attributable to a physical change, can trigger an emissions increase for PSD purposes:

> Actual emissions are the product of the emissions rate (amount of pollution per unit of production or throughput, e.g., pounds of sulfur dioxide per ton of coal combusted), the production rate or capacity utilization (amount of production or throughput per hour, e.g., tons of coal combusted per hour) and the *hours of operation* (e.g., hours per year). In its prior determination, EPA explained

> that *an increase in any one of these three factors, if attributable to a physical or operational change, can trigger an emissions increase for PSD purposes*, and rejected WEPCO's contention that only increases in the emission rate were determinative.

PTX 141 at 9 (emphasis added). Thus, EPA here gave notice than an increase in hours of operation due to a project "can trigger an emissions increase for PSD purposes." Finally, in the preamble to the 1992 PSD regulations, EPA confirmed this theory of PSD applicability, stating that: "an increase in emissions attributable to an increase in hours of operation . . . which is the result of a construction-related activity is not excluded from [PSD] review." 57 Fed. Reg. 32314, 32328 (1992) [PTX 2217 (d)]. Thus, under the *Cinergy* standard, Allegheny had repeated notice of the basis for plaintiffs' PSD claims in this case: the regulations and guidance informed Allegheny that projects at coal-fired generating units could cause increases in utilization that, in turn, could result in an increase in emissions that would trigger PSD applicability.

Moreover, even setting aside the *Cinergy* standard, Allegheny had fair notice of the methodology Dr. Rosen used because his five-step approach represented standard scientific and engineering principles recognized at the time of the projects, and in fact Allegheny or the utility industry used every part of that five-step approach to calculate emissions in the 1990s.[65]

In sum, the regulations and guidance provided notice that projects could increase utilization and emissions. Dr. Rosen's five equations were based on general industry knowledge, T.T., Sept. 21, 2010, at 135:19-136:3, and as shown above Allegheny used the same equations and assumptions as Dr. Rosen. Finally, EPA regulations and guidance provided notice of plaintiffs' interpretation of the netting requirements, and contemporaneous industry advisory

[65] Allegheny of course argues that aspects of what Dr. Rosen did were wrong, but that is a merits argument, not a fair notice argument.

materials demonstrate that that interpretation was understood in the 1990s. For all of the reasons provided, Allegheny had fair notice of the PSD emissions standards.

VIII. ALLEGHENY'S STATUTE OF LIMITATIONS DEFENSE IS MERITLESS

A. Summary of Argument

The Court has already ruled that the statute of limitations does not bar either plaintiffs' federal law claims, to the extent they request equitable relief, or PA DEP's state-law claims in any respect. Docket Item 45 at 9-12, *as adopted by* Docket Item 50; Docket Item 380 at 8 n. 2, 10. The remaining question is whether the statute of limitations bars any of plaintiffs' federal claims to the extent they request civil penalties. As shown below, plaintiffs have proven that the statute of limitations – at least with respect to those claims related to projects undertaken by Allegheny at the same time as low NO_x burner installation – should be equitably tolled.[66]

B. The Legal Standard for Equitable Tolling

Before trial, the Court held that a statute of limitations may be equitably tolled when "a defendant actively misleads a plaintiff with respect to [his/her] cause of action." Docket Item 380 at 12. To toll on the basis of misleading conduct, a plaintiff does not have to show "egregious acts of active deception," *Meyer v. Riegel Prods. Corp.*, 720 F.2d 303, 307-08 (3d Cir. 1983), or proof of fraudulent intent, *Veltri v. Building Serv. 32B-J Pension Fund*, 393 F.3d 318, 323 (2d Cir. 2004). Instead, a statute of limitations is tolled upon a showing that a defendant's "acts or omissions . . . lulled the plaintiff into foregoing prompt attempts to vindicate his rights." *Bonham v. Dresser*, 569 F.2d 187, 193 (3d Cir. 1978); *see also Meyer*, 720 F.2d at

[66] Plaintiffs preserve their objections to the Court's previous rulings that the federal claims are not continuing or ongoing daily violations, and that the discovery rule does not apply to those claims. Docket Item 45 at 6-7 (continuing/daily violations), *as adopted by* Docket Item 50; Docket Item 380 at 13 (discovery rule).

307 (same). Under such circumstances, however, a plaintiff must show that it exercised due diligence. *Santos v. United States*, 559 F.3d 189, 197 (3d Cir. 2009).

C. Equitable Tolling Applies to the Claims Related to Projects Performed at the Same Time As the Installation of the Low-NO_x Burners

In 1994, Allegheny applied for plan approvals to install low-NO_x burners at Armstrong, Hatfield's Ferry and Mitchell to comply with RACT requirements. PTX 253; PTX1216; PTX 1218. The Pennsylvania regulations applicable at the time required those applying for such plan approvals to demonstrate, among other things, "that the source will comply with [all] applicable requirements of [Pennsylvania's air quality regulations] and requirements . . . under the Clean Air Act." 25 Pa. Code § 127.12(a)(4) [PTX 2209 (d)].

Allegheny's RACT applications and related submissions, however, did not mention other work Allegheny performed at the same time as the RACT low-NO_x burner projects. As a result, in those applications and related material Allegheny failed to disclose the Armstrong PSD Projects, the 1993 Hatfield's Ferry 2 reheater PSD Project, and the Mitchell 3 lower slope PSD Project, and failed to fully disclose the Armstrong Reconstruction projects, of which the Armstrong PSD Projects were a major part. *See* PTX 253 *passim*; PTX1216 *passim*; PTX 1218 *passim*; *see also* PTX 1333 *passim*; PTX 1334 *passim* (Allegheny RACT proposals for Armstrong submitted to PA DEP). Because the RACT plan approval applications did not disclose this work or the implications of the work for compliance with federal and Pennsylvania air pollution law – despite a legal duty to do so – equitable tolling applies to any claims related to the Armstrong Reconstruction Projects, the Armstrong PSD Projects, or the identified Hatfield's Ferry and Mitchell PSD Projects.[67]

[67] Allegheny directed those misleading applications to PA DEP, so equitable tolling clearly applies to the federal claims as brought by PA DEP. Connecticut, Maryland, New Jersey

This case is indistinguishable from *Veltri*, cited above. In *Veltri*, the applicable regulations required that, when a pension fund made an adverse benefits determination, it had to provide the claimant with information: notice of his right to file a lawsuit challenging the determination. 393 F.3d at 323. The *Veltri* defendants had provided the plaintiff with a booklet informing him of *some* of his rights but *not* of his right to file an action in court. *Id.* While acknowledging that such nondisclosure normally would not mandate equitable tolling, the court ruled that, when there is a regulatory notice requirement and an accompanying policy of protecting the interests of pension plan participants, failure to provide such notice constitutes "the type of concealment that entitles plaintiff to equitable tolling of the statute of limitations." *Id.* at 324. *See also Oshiver v. Levin, Fishbein, Sedran & Berman*, 38 F.3d 1380, 1391-92 (3d Cir. 1994) (reversing district court's dismissal of claim when a law firm fired an employee for lack of work but there allegedly was such work); *Bonham*, 569 F.2d at 193 (reversing summary judgment in favor of defendant employer when there were factual questions about whether the employer had posted notices required under antidiscrimination law).

Like the defendants in *Veltri*, Allegheny had a legal duty to provide information: information about the work Allegheny intended to perform at the same time it installed the low-NO_x burners and the air pollution control implications of that work. The Pennsylvania plan approval application requirements, like the regulatory requirements at issue in *Veltri*, have an overarching public purpose: to provide PA DEP with the information it needs to ensure that emissions from the units either did not worsen air quality in areas that meet national standards or

and New York do not invoke equitable tolling as to their federal claims. A finding that equitable tolling applies to PA DEP's federal claims would be sufficient to maintain the claims for federal civil penalties, since such penalties accrue to the federal government, not to the plaintiffs. 42 U.S.C. § 7604(g).

help improve air quality in areas that did not meet standards. 25 Pa. Code § 127.1 [PTX 2209 (d)].

Plaintiffs have also proven that PA DEP exercised due diligence. PA DEP reviewed the RACT plan approval applications and other materials that Allegheny submitted in connection with the installation of the low-NO_x burners, but those materials did not include any information related to the PSD Projects being undertaken at the same time as the low-NO_x burner installations. T.T., Sept. 14, 2010, at 100:12-101:16, 103:12-104:14, 105:11-111:5 (Armstrong); T.T. Sept. 14, 2010, at 113:22-118:10, 119:15-122:18 (Hatfield's Ferry); 118:11-119:14, 122:19-123:2 (Mitchell).

Allegheny presented no evidence at trial that PA DEP was on notice of the 1993 Hatfield's Ferry 2 reheater project or the Mitchell 3 lower slope project until PA DEP received Allegheny's section 114 documents in 2004. Similarly, with respect to Armstrong, Allegheny failed to offer any convincing evidence that supports a finding that PA DEP was on notice of either the PSD Projects or the full scope of the Reconstruction Projects. For example, former Allegheny executive Mr. Colby testified that Allegheny did not inform PA DEP of the work done in the PSD Project. T.T., Sept. 23, 2010, at 216:3-21. Mr. Colby's admission is consistent with the testimony of Mark Wayner, the current air quality program manager for PA DEP's southwest regional office, who worked on the Armstrong RACT applications in the mid-1990s. T.T. Sept. 14, 2010, at 75:4-8, 103:12-17. Mr. Wayner testified that he first became aware that Allegheny had performed the PSD Project work in 2004. T.T., Sept. 14, 2010, at 188:14-189:21.

Although PA DEP did inspect Armstrong during the 1995 outage, the purpose of that inspection was to confirm that Allegheny was installing the low-NO_x burners. D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 18:21-22. Nothing in the inspection report indicates that the

inspector learned that Allegheny was doing additional work, namely, the PSD Projects. DTX 557 at PA INSP REP 0001333 (inspection report nowhere identifying work done on convection superheater, reheater , or economizer or convection section in general); *see also* D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 18:4-20:10 (inspector did not know what work Allegheny was performing other than removing asbestos).

Allegheny itself had told PA DEP that it needed a 32-week outage to do the work necessary to install the low-NO_x burners. PTX 322 at AE_HQ_00140176. So when the inspector arrived in 1995 during the Armstrong 1 outage, the situation was consistent with Allegheny's prior representation that it would be performing extensive work to install the low-NO_x burners. There was thus no reason to suspect that Allegheny was in fact doing additional unrelated work. Just as an application for a fishing license would not put a state game agency on notice that the applicant was going to go hunting, Allegheny's RACT-related disclosures would suggest to a reasonable person that Allegheny was performing the RACT work, and gave no reason to suspect additional work that might violate the NSPS, BAT, PSD or nonattainment NSR requirements.

IX. ALLEGHENY'S REMAINING DEFENSES ALSO FAIL

A. Summary of Argument

Aside from fair notice and the statutes of limitations, Allegheny asserts a number of other affirmative defenses. Plaintiffs have already addressed many of them. Allegheny's fifth affirmative defense is that it is in full compliance with federal and state clean air law, and its seventh affirmative defense is that it has been in full compliance with relevant law in undertaking the projects of the type at issue in this case. *See* PTX 2 at 42, 43. Allegheny has not proven those defenses for all of the reasons set out in this brief. Similarly, plaintiffs have

already addressed Allegheny's fourth affirmative defense, regarding purportedly inadequate notice of intent to sue, and its ninth affirmative defense, regarding whether the projects at issue in this case were "physical changes" for the purpose of PSD liability. *See* Argument section I (notice issues) and IV.C.2 and IV.D.2 (physical change) above.

The remaining affirmative defenses include laches, waiver, collateral estoppel and several others. None of these remaining defenses have merit.

B. <u>Allegheny Cannot and Has Not Established Laches</u>

Allegheny asserts laches as part of its third affirmative defense, PTX 2 at 42, but that defense is not available on the law and the facts of this case. Laches is a "neglect to assert a right or claim which, taken together with lapse of time and other circumstances causing prejudice to adverse party, operates as bar in court of equity." *Black's Law Dictionary* 875 (6th ed. 1990). Thus, the elements of a laches defense are: (1) inexcusable delay in instituting suit and (2) prejudice to the party asserting the defense. *Central Pa. Teamsters Health & Welfare Fund v. McCormick Dray Lines, Inc.*, 85 F.3d 1098, 1108 (3d Cir. 1996).

Normally, the party asserting laches has the burden of establishing the elements of the defense. *United States v. Koreh,* 59 F.3d 431, 445-446 (3d Cir. 1995). If a limitations period for legal relief has passed, however, the burden of proof on a laches defense to equitable relief shifts to the claimant. *E.E.O.C. v. Great Atlantic & Pacific Tea Co.*, 735 F.2d 69, 80 (3d Cir. 1984). Plaintiffs maintain their position that the statute of limitations has not run, *see* Argument section VIII above, and accordingly assert that Allegheny bears the burden on this defense. Even if the Court finds otherwise, however, plaintiffs demonstrate below that laches does not bar their claims for several reasons.

First, as an equitable defense, laches is not available on claims for legal relief, and in particular civil penalties, so laches does not bar plaintiffs' claims to the extent they seek such penalties. *United States v. American Elec. Power*, 218 F. Supp. 2d 931, 937 (S.D. Ohio 2002). Second, as a general rule, laches is not a defense to a suit by the government to enforce a public right or protect a public interest. *Utah Power & Light Co. v. United States*, 243 U.S. 389, 409 (1917). Thus, laches did not bar claims by the United States in an action alleging Clean Air Act PSD violations. *United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122, 1138 (D. Colo. 1987). Because plaintiffs in this case are states or a state agency, and they are acting under the Clean Air Act citizen suit provisions to enforce and protect the same public rights and interests that the United States does when it brings suit under that statute, laches does not bar the plaintiffs' claims for equitable relief. *Natural Res. Def. Council v. Fox*, 909 F. Supp. 153, 160 (S.D.N.Y. 1995) ("[b]ecause a citizen suit . . . is a suit to protect the public interest, laches does not apply"); *Student Pub. Interest Research Group of N.J., Inc. v. P.D. Oil & Chem. Storage, Inc.*, 627 F. Supp. 1074, 1085 (D.N.J. 1986) ("as citizens stand in the shoes of the government 'as private attorneys general,' it makes no sense to apply laches in a citizen suit"); *see also* .*Middlesex Cty. Sewerage Auth. v. Nat'l Sea Clammers Ass'n*, 453 U.S. 1, 16-17 (1981) (purpose of citizen suit provision was to authorize others to act as "private attorneys general").

Third, even if laches were available as a defense, the facts necessary to establish it are not present. There was no inexcusable delay: plaintiffs obtained the documents regarding the projects in this case in early 2004, PTX 202 at AE_HQ_00308330, and sent notice letters in May and September 2004, PTX 17, PTX 18. After months of settlement negotiations between the parties, Allegheny filed suit in West Virginia in January 2005 to seek a declaratory judgment regarding its activities, and plaintiffs filed this lawsuit in June 2005, approximately 15 months

after receiving the documents. That is not inexcusable delay. *See, e.g., Central Pa. Teamsters*, 85 F.3d at 1108 (no laches when party had filed suit to collect a delinquency 19 months after its audit revealed the delinquency). In addition, there was no prejudice from that 15-month delay, which included 10 months during which Allegheny itself waited to file its West Virginia suit.

Moreover, even assuming for the sake of argument that delay would be measured from the time of the projects in the 1990s, as Allegheny may contend, Allegheny has not suffered any prejudice. To the contrary, any such "delay" has benefited Allegheny to the extent that it has allowed Allegheny to postpone expenditures on pollution control equipment. In fact, the passage of time appears to have made such equipment less expensive now than it was in the 1990s. *Compare* PTX 119 at AE_HQ_00286816 (document from early 1990s finding that scrubbers could be installed at Armstrong at a cost of $1,423 per ton of SO_2 removed) *with* PTX 125 at AE_HQ_00268943 (Table S-2) (2001 document finding that scrubbers could be installed at Armstrong at a cost of $700-$760 per ton of SO_2 removed)). In addition, as far as its ability to defend itself in this case, Allegheny suffered no prejudice: it was able to present witnesses at trial who worked at Allegheny during the time of the projects and able to produce over a million pages of documents from the relevant time period in discovery.

C. <u>Allegheny Has Not Established Waiver</u>

Allegheny also asserts waiver as part of its third affirmative defense, PTX 2 at 42, but has not established it. Waiver is the "intentional relinquishment of a known right." *Central Pa. Teamsters*, 85 F.3d at 1109. On this defense, Allegheny bears a high burden of proof, as the evidence must show that the waiver was "clear and unmistakable." *Id.* Allegheny has introduced no evidence that plaintiffs knew about the claims in this action before 2004, let alone

clearly and unmistakably relinquished any such claims. *Id.* (finding no waiver when plaintiff failed to respond to defendant's notification regarding contract issues).

D. Allegheny Has Not Established Collateral Estoppel

Allegheny also asserts collateral estoppel as part of its third affirmative defense, PTX 2 at 42, but has not established it. To apply the doctrine, Allegheny must prove the following four elements with regard to an issue in the case: "(1) the identical issue was previously adjudicated; (2) the issue was actually litigated; (3) the previous determination was necessary to the decision; and (4) the party being precluded from relitigating the issue was fully represented in the prior action." *Howard Hess Dental Labs. Inc. v. Dentsply Int'l, Inc.*, 602 F.3d 237, 247-248 (3d Cir. 2010). Allegheny has not shown that any issue with respect to the claims in this case has ever been previously adjudicated, let alone established the other three elements. The fact that Allegheny has not asserted collateral estoppel with respect to any issue in the motion to dismiss, summary judgment and other briefs it has filed in this 5 ½-year-old litigation confirms that Allegheny has no such defense.

E. Allegheny's Defense Regarding the Cause of Actual Emissions Increases Is Invalid as a Matter of Law

As its eighth defense, Allegheny pleads that any significant increases in emissions following the projects resulted from increases in demand or load or for other reasons independent of the projects at issue in this case. PTX 2 at 43. To the extent that this defense turns on what actually happened to emissions after the projects, it is contrary to the "actual-to-projected future" emissions test for PSD liability, which is the law of the case and the holding of every other final ruling regarding the proper PSD emissions test. *See* Argument section IV.C.3 above. Even if the defense were available, Allegheny offered no evidence proving that any increases in pollution after the projects were due to factors independent of the projects.

F. <u>Allegheny's Defense Regarding Damages Is Invalid as a Matter of Law</u>

As its tenth defense, Allegheny asserts that plaintiffs have not suffered injuries or damages. PTX 2 at 43. Because the claims in this case are for statutory and regulatory violations, proof of injuries or damages is not an element of liability. *See* Argument sections II.B, III.B, IV.B, V.B and VI.B above. Accordingly, the absence of such proof is not a defense to liability.

G. <u>Allegheny's Defense Regarding Significant Net Emissions Increases Fails</u>

As its eleventh defense, Allegheny asserts that plaintiffs have not proven that the projects at issue caused significant net emissions increases. PTX 2 at 44. The defense is ambiguous, as it is not clear whether Allegheny is referring to *actual* post-project emissions increases or *projected* post-project emissions increases, but under either interpretation it fails. To the extent that Allegheny is asserting a defense based on what *actually* happened to emissions after the projects, the defense is invalid as a matter of law because the PSD and nonattainment NSR emissions tests turn on projections of future emissions made before undertaking the project, not what actually happens after the project is completed. *See* Argument section IV.C.3 above.

To the extent Allegheny is asserting a defense based on emissions projections, plaintiffs have met their burden under the PSD and nonattainment NSR regulations. *See* Argument sections IV.C.3 and V.C.4 above.

H. <u>Allegheny's Hourly Emissions Rate Defense Is Invalid as a Matter of Law</u>

As its twelfth defense, Allegheny asserts that plaintiffs have failed prove that the projects at issue caused an increase in the hourly rate of emissions. PTX 2 at 44. This defense is invalid for the NSPS, BAT and Title V claims because emissions increases are not an element of those claims. *See* Argument sections II.B, III.B and VI.B above. This defense is invalid for the PSD

claims because the Supreme Court held that the PSD emissions test is annual, not hourly. *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 577-78 (2007). This defense is invalid for the nonattainment NSR claims because plaintiffs have proven their case using annual emissions, not hourly emissions. *See* 25 Pa. Code §§ 127.203(a)(2) & (b)(1) [PTX 2209 (d)] (setting alternative annual, daily or hourly thresholds for nonattainment NSR applicability).

I. Allegheny's Maximum Achievable Emissions Rate Defense Fails

As its thirteenth affirmative defense, Allegheny asserts that plaintiffs have failed to prove that the projects at issue caused an increase in the "maximum achievable emissions rate." PTX 2 at 44. This defense is invalid for the NSPS, BAT and Title V claims because emissions increases are not an element of those claims. *See* Argument sections II.B, III.B and VI.B above. This defense is invalid for the PSD claims because the relevant test is actual-to-projected-future-actual, not the "maximum achievable emissions rate." *See* Argument section IV.C.3 above. As for the nonattainment NSR claims, to the extent Allegheny intends "maximum achievable emissions rate" to mean potential to emit, plaintiffs have met their burden. *See* Argument section V.C.4 above.

J. Allegheny's Fourteenth Defense Also Fails

In its fourteenth affirmative defense, Allegheny contends that the projects at issue meet the regulatory standards in the five plaintiff states, and that the plaintiffs' actions in this case conflict with regulatory actions in those states. PTX 2 at 44. As shown above, plaintiffs have proven that Allegheny is liable for NSPS, PSD, Title V, BAT and nonattainment NSR violations under the federal and Pennsylvania statutes, regulations and guidance in effect at the time of the projects, and the evidence Allegheny presented does not defeat those showings. *See* Argument sections II, III, IV, V and VI above. In addition, because the Armstrong, Hatfield's Ferry and

Mitchell plants are in Pennsylvania, the laws, regulations and guidance in Connecticut, Maryland, New Jersey and New York are irrelevant, and in any event Allegheny presented no evidence at trial regarding those other states' laws, regulations and guidance.

X. THE DEFENDANTS ARE LIABLE AS OWNERS AND/OR OPERATORS OF THE ARMSTRONG, HATFIELD'S FERRY AND MITCHELL 3 UNITS

Under the citizen suit provision of the Clean Air Act, this Court can find a "person" liable for violations of federal emissions standards or limitations or for undertaking a major modification without a PSD permit. 42 U.S.C. § 7604(a)(1) & (3). The term "person" includes an individual, corporation, partnership, or other entity. 42 U.S.C. § 7602(e). All of the defendants named in this action are "persons" under 42 U.S.C. § 7602(e). Docket Item 430 ¶ 3.

Similarly, under Pennsylvania law, this Court can hold a "person" liable for violations of the Pennsylvania air pollution regulations. *See, e.g.,* 35 P.S. § 4009 (authorizing the award of penalties against "any person" who violates the Pennsylvania Air Pollution Control Act or its implementing regulations). Pennsylvania law defines "person" to include individuals, public or private corporations for profit or not for profit, associations, partnerships, and other entities. *See* 35 P.S. § 4003. Because defendants satisfy the federal definition of person, they are also persons for the purposes of the Pennsylvania definition.

Each defendant is liable as an owner or operator of one or more of the Armstrong, Hatfield's Ferry and Mitchell power stations. Under the Clean Air Act, an "owner or operator" is "any person who owns, leases, operates, controls or supervises a stationary source." 42 U.S.C. § 7411(a)(5). Pennsylvania law defines an "owner or operator" using the same language: "[a] person who owns, leases, operates, controls or supervises a source or facility." *See* 25 Pa. Code § 121.1. Under those standards, the defendants are each an owner and/or operator of one or more of the generating units:

Monongahela: At all times pertinent to this action, Monongahela was an owner of the Armstrong, Hatfield's Ferry and Mitchell generating stations. PTX 1 ¶ 3; PTX 2 ¶ 3. As of the mid-1990s, for example, when the projects at issue were being undertaken, Monongahela owned 456 of the total of 1,660 megawatts (28 percent) of the capacity at the Hatfield's Ferry plant. PTX 23 at 15 (page 16 of original document).

Potomac: Potomac is an owner and operator of the Hatfield's Ferry plant because until August 1, 2000, Potomac participated in the operation of, and partially owned, that facility. PTX 1 ¶ 27; PTX 2 ¶ 27. In the mid-1990s, for example, when the projects at issue were being undertaken, Potomac owned 332 of the total of 1,660 megawatts (20 percent) of the capacity at the Hatfield's Ferry plant. PTX 23 at 15 (page 16 of original document).

West Penn: West Penn is an owner and operator of the Armstrong, Hatfield's Ferry and Mitchell power stations because until November 1999 West Penn operated and owned the Armstrong facility and the Mitchell facility and also participated in the operation of, and partially owned, the Hatfield's Ferry facility. PTX 1 ¶ 28; PTX 2 ¶ 28. In the mid-1990s, for example, when the projects at issue were being undertaken, West Penn owned 872 of the total of 1,660 megawatts (52 percent) of the capacity at the Hatfield's Ferry plant. PTX 23 at 15 (page 16 of original document). In addition, during the same timeframe, West Penn owned 100 percent of the capacity of the Armstrong plant and 100 percent of the capacity of Mitchell 3. PTX 23 at 15 (page 16 of original document).

Allegheny Supply: At all times pertinent to this action, Allegheny Supply was an owner of the Armstrong, Hatfield's Ferry and Mitchell generating stations. PTX 1 ¶ 3; PTX 2 ¶ 3. By 2007, for example, Allegheny Supply owned the total coal-fired capacity of the Armstrong, Hatfield's Ferry and Mitchell plants. PTX 35 at 16.

Allegheny Service: Under the Clean Air Act, to "operate" a source means to manage, direct, or conduct operations specifically related to polluting activities, including decisions about compliance with environmental regulations. *United States v. Anthony Dell'Aquilla, Enters.*, 150 F.3d 329, 334 (3d Cir. 1998). Allegheny Service operates, controls and supervises the Armstrong, Hatfield's Ferry and Mitchell power stations by virtue of the fact that it provided management and professional services relevant to the projects at issue in this case to Allegheny Energy, Allegheny Supply, Monongahela, Potomac, and West Penn, including environmental, accounting, administrative, information systems, engineering, financial, legal, maintenance and other services. PTX 1 ¶ 24; PTX 2 ¶ 24. Allegheny Service provides such services to the other defendants as the actual employer of Allegheny Energy's officers and the actual employer of substantially all of the other Allegheny entities' employees. PTX 20 – PTX 35 at Part 1, Item 1; D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), May 3, 2007, at 39:3-14). Thus, for example, Allegheny Service employed Allegheny's director of environmental services, and Allegheny Service's employees communicate directly with state and federal regulators with respect to environmental issues involving the other five defendants. D.T. (Peter Skrgic 30(b)(6) witness on corporate organization), May 2, 2007, at 60:3-61.1; PTX 1 ¶ 30; PTX 2 ¶ 30.

Allegheny Energy: Allegheny Energy owns, controls and supervises the Armstrong, Hatfield's Ferry and Mitchell power stations through its ownership of Allegheny Service, Allegheny Supply, Monongahela, Potomac and West Penn. Docket Item 430 ¶ 1, Docket Item 430 ¶ 2. Under the Clean Air Act, when a parent corporation owns a subsidiary that in turn owns a facility, the parent corporation can be held liable as an owner of the facility. *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 832, 890 (S.D. Ohio 2003) (holding parent corporation Ohio Edison Co. liable). Allegheny has described itself as an integrated energy business that

owns and operates electric generation facilities. PTX 1 ¶ 30; PTX 2 ¶ 30. Thus, in the mid-1990s, Allegheny Energy owned the Hatfield's Ferry plant through its ownership of Monongahela, Potomac and West Penn, and owned Armstrong and Mitchell 3 through its ownership of West Penn. Docket Item 430 ¶ 2; PTX 666 at AE_HQ99669008; PTX 23 at 15 (page 16 of original document) (Monongahela owned 456, Potomac owned 332, and West Penn owned 872, of the 1,660 megawatts at Hatfield); *id.* (West Penn owned 284 of 284 megawatts at Mitchell 3 and 352 of 352 megawatts at Armstrong); D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), May 3, 2007, at 34:1-24. In 2007, Allegheny Energy owned Armstrong, Hatfield's Ferry and Mitchell 3 through its ownership of Allegheny Supply. Docket Item 430 ¶ 2; PTX 666 at AE_HQ00669006 - 007. Consistent with this description, Allegheny Energy derived substantially all of its income from its subsidiaries including Monongahela, Potomac and West Penn for the years 1993 through 1998; and, beginning in 1999, Allegheny Supply as well. PTX 20 - PTX 26 at Part 1, Item 1. The senior officers and directors of Allegheny Energy were paid in part based on their work for the other defendants. PTX 36 - PTX 42 at Item 6.

XI. RELIEF REQUESTED

The Court bifurcated this proceeding into liability and remedy phases. Docket Item 59 ¶ 2. In this phase, on the law and evidence set out above, plaintiffs respectfully ask that the Court find liability on plaintiffs' claims as follows:

A. NSPS

On claims 4, 5, 10 and 11 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania NSPS reconstruction regulations, with respect to SO_2, arising out of Allegheny's performance of the Armstrong Reconstruction Projects.

B. Pennsylvania New Source Permitting/BAT

On claims 6 and 12 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the Pennsylvania new source permitting regulations and their BAT emissions control requirement, with respect to SO_2, NO_x, ozone, particulate matter, mercury and other hazardous air pollutants, arising out of Allegheny's performance of the Armstrong Reconstruction Projects.

C. PSD

On claims 1, 2, 7 and 8 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania PSD regulations, with respect to NO_x, arising out of Allegheny's performance of the Armstrong PSD Projects.

On claims 15 and 16 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania PSD regulations, with respect to SO_2 and NO_x, arising out of Allegheny's performance of the Hatfield 1 secondary superheater outlet header PSD Project, the Hatfield 1 lower slope PSD Project, or both.

On claims 17 and 18 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania PSD regulations, with respect to SO_2 and NO_x, arising out of Allegheny's performance of the Hatfield 2 pendant reheater PSD Project, the Hatfield 2 lower slope PSD Project, or both.

On claims 19 and 20 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania PSD regulations, with respect to SO_2 and NO_x, arising out of Allegheny's performance of the Hatfield 3 lower slope PSD Project.

On claims 23 and 24 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania PSD regulations, with respect to NO_x, arising out of Allegheny's performance of the Mitchell 3 lower slope PSD Project.

D. Pennsylvania Nonattainment NSR

On claims 3 and 9 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the Pennsylvania nonattainment NSR regulations, with respect to SO_2 and ozone (NO_x), arising out of Allegheny's performance of the Armstrong Reconstruction Projects.

E. Title V

On claims 13 and 14 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal Title V regulations with respect to SO_2 and NO_x, and for violations of the Pennsylvania Title V regulations with respect to SO_2, NO_x, ozone, particulate matter, mercury and other hazardous air pollutants, arising out of Allegheny's failure to report the Armstrong Reconstruction Projects and PSD Projects in its Title V application for the Armstrong plant or subsequently.

On claims 21 and 22 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania Title V regulations, with respect to SO_2 and NO_x, arising out of Allegheny's failure to report the Hatfield PSD Projects in its Title V application for the Hatfield plant or subsequently.

On claims 25 and 26 of plaintiffs' amended complaint, PTX 1, the Court should find Allegheny liable for violations of the federal and Pennsylvania Title V regulations, with respect to NO_x, arising out of Allegheny's failure to report the Mitchell 3 lower slope PSD Project in its Title V application for the Mitchell plant or subsequently.

CONCLUSION

For the reasons given above, the Court should adopt the plaintiffs' proposed conclusions of law and find that Allegheny is liable on all of plaintiffs'claims.

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Respectfully submitted,

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